Application No: A.14-12-______________
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-____ (Filed December 18, 2014

PREPARED DIRECT TESTIMONY OF

STEVE WATSON

SOUTHERN CALIFORNIA GAS COMPANY AND

SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

December 18, 2014

TABLE OF CONTENTS

PREPARED DIRECT TESTIMONY

OF STEVE WATSON

I. PURPOSE

The purpose of my direct testimony on behalf of Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) is to describe the storage and balancing framework that should replace that of the 2009 BCAP Phase 1 Settlement. That settlement was adopted in Decision (D.) 08-12-020 and covered the years 2009-2014, but the storage-related provisions of the settlement were ultimately extended through the year 2015 by D. 14-06-007. The testimony addresses the following items:

- Total Storage Capacities
- The Balancing Function
- Core Storage allocations
- Unbundled Storage Allocations
- Storage Function Costs
- Necessary modification of the G-TBS tariff
- Unbundled Storage Sharing Mechanism
- Postings of Unbundled Storage Transactions
- Aliso Canyon and storage in-kind fuel
- Information system modifications and costs

II. TOTAL STORAGE CAPACITIES

The total capacities established for the current TCAP period are 138.1 Bcf of inventory (as of January 1, 2015, post Honor Rancho expansion), 850 MMcfd of summer injection capacity, and 3,195 MMcfd of winter withdrawal capacity. The 7 Bcf Honor Rancho expansion will be completed in 2015, and total inventories will remain at 138.1 Bcf for the 2016-2019 period.

Injection capacity for the summer period (April-October) of 2016 should be lowered from 850 MMcfd to 770 MMcfd. The 2014 injection season injection capacity posted on Envoy averaged 785 MMcfd.[1] The recommended 770 MMcfd figure was available 71% of those days, so this figure should be sufficient to avoid significant pro-rationing of firm injection nominations during the summer under Rule 30. Both core and unbundled storage customers expressed concerns about such pro-rationing over the last several summers.

Storage injection capacity has been adversely impacted by two primary factors. First, there was maintenance at old compressor facilities during the injection season at SoCalGas' storage fields other than Aliso Canyon. A decade ago, maintenance on these units could be focused in the winter period. The age of these other, smaller compressor units, however, has created maintenance issues throughout the year. This situation is expected to continue through the next TCAP period unless there are other compressor unit replacements such as is underway now at Aliso Canyon.

Second, there has been a long-term, 40 MMcfd decline in the injection capability at Goleta that has been posted on the Envoy system: "Non Maintenance related due to North Coastal demand and available supply." Given the dramatic reductions in Coastal California production, over 40 MMcfd of interstate supplies that would otherwise be injected into Goleta during the summer must instead be used to serve Coastal demand during the summer. SoCalGas does not expect this situation to change over the next TCAP period.

[1] 2012 and 2013 had significant injection issues caused by maintenance issues at Aliso Canyon that should be remedied with the Aliso Canyon Turbine Replacement Project approved in D. 13-11-023.

Injection capacity will increase by 145 MMcfd with the Aliso Canyon Turbine Replacement Project, but that incremental capacity will not come on-line before 2017. Therefore, I recommend a total summer (April-October) injection capacity of 770 MMcfd for 2016 and 915 MMcfd for 2017-2019.

The allocation of costs among the balancing, core, and unbundled functions that I am recommending later in this testimony requires that “off-cycle” firm rights be established for injection in the winter and for withdrawal in the summer. Injection availability postings over the last four winters have averaged 390 MMcfd. Therefore, I am recommending establishing 390 MMcfd as the firm injection figure for the winter period of 2016. The new turbines at Aliso Canyon should increase this figure by 145 MMcfd (to 535 MMcfd) for the following winter periods.[2] My cost allocation proposal discussed in Section VI below is consistent with these capacities.

The firm withdrawal capacity over the winter should be lowered from the 3,195 MMcfd set for the current TCAP period to 3,175 MMcfd. Although 3,680 MMcfd of deliverability is available when storage is full, deliverability drops to 3,175 MMcfd when storage inventory falls to 34 Bcf. Over the last three winters, inventory has remained over 34 Bcf more than 90% of the winter days. Therefore, pro-rationing of firm rights should be rare using the 3,175 MMcfd figure since inventories do not typically fall below 34 Bcf, if at all, until late February or March—a period in which the core’s need for its full 2,225 of firm rights typically drops several hundred MMcfd as the weather gets warmer.

Due to maintenance of withdrawal capabilities during the summer, total firm withdrawal over the summer should be set at 1,812 MMcfd, which is below posted withdrawal capacity over

[2] Whatever winter injection is not allocated to the balancing function would be allocated to the core in order to provide more purchasing flexibility to the Utility Gas Procurement Department and Core Transportation Agents.

the last three summers more than 85% of the days. As will be apparent later in this testimony, this requires that the firm withdrawal rights of unbundled storage and core customers (not balancing rights) be reduced by 50 percent over the 214 days of the summer. My cost allocation proposal below will be consistent with these firm winter/summer capacity figures.

III. THE BALANCING FUNCTION

SoCalGas and SDG&E are proposing low OFO procedures in A.14-06-021.[3] That proposal resembles the procedures that have served Pacific Gas & Electric Company (PG&E) and its customers well over the last decade. The implementation of a similar OFO mechanism at SoCalGas and SDG&E would allow the elimination of both the winter balancing rules in both utilities' Rule 30 and the Curtailment of Standby Procurement authority contained in SoCalGas Rule 23 and SDG&E Rule 14. PG&E's rules allow for a low OFO any time during the year regardless of inventory levels, they allow more appropriate flexibility in tolerance levels, they allow for more appropriate noncompliance charges based on the economic circumstances leading to underdeliveries, and they ensure that transportation customers do not excessively rely on storage by using storage assets beyond those allocated in the cost allocation process. For all the reasons stated in that testimony, SoCalGas believes that PG&E-like OFO rules will ensure that there are adequate supplies coming into its system throughout the year and, thereby, minimize the likelihood of any system-wide curtailment issues.[4] We also believe PG&E-like rules will be more predictable, reasonable, and customer-friendly than SoCalGas and SDG&E's current rules.

Under SoCalGas and SDG&E's proposal, a low OFO would be triggered whenever it is forecasted that transportation customers are using more withdrawal than can be accommodated

---

[3] For reference, I have included a copy of my direct testimony in support of A. 14-06-021 as Attachment A to this testimony.

[4] Localized curtailments will still need to be addressed in Rule 23, but SoCalGas intends to file an Application soon that will refocus Rule 23 to deal specifically with the issue of localized curtailments caused by local capacity constraints, rather than a lack of supply.

with the assets allocated to the balancing function. The amount of storage withdrawal (or injection) being used for transportation customer balancing is shown on the "information postings" section of Envoy, "Operations," "Daily Operations," the line titled "Storage Injection for Customer Balancing (Withdrawal)." The only difference between PG&E and SoCalGas and SDG&E's proposal is that SoCalGas and SDG&E's asset allocated to daily balancing is solely storage withdrawal, whereas PG&E is able to allocate a significant amount of linepack to the daily balancing function.[5] SoCalGas and SDG&E have already agreed to amend its noticing procedures and its standby rate to be comparable to PG&E's in the Low OFO proceeding.[6] I will discuss how much withdrawal should be allocated to this balancing function later in this text. Using the current allocation to balancing, the trigger for a low OFO at SoCalGas and SDG&E would be: If forecasted receipts – forecasted sendout – forecasted net withdrawals (a negative number) from storage accounts < - 340 MMcfd, then low OFO.[7]

Under Rule 30, this amount would be set aside daily for balancing customers' use and would have the highest storage priority. Any remaining capacity would be allocated each day to storage customers in the manner described in revised Rule 30—firm withdrawal first, then volumetrically-priced, interruptible withdrawals would be prioritized by price and prorated, if necessary, to accommodate remaining capacity.[8] Proposed revisions to SoCalGas Rule 30 are included in Attachment B to this testimony. By definition then, as long as transportation customers use less withdrawal than is allocated to the balancing function, there should be no

[5] SoCalGas reserves its limited linepack to deal with unpredictable variations within a day—i.e., for intra-day, hourly balancing.
[6] *See* Prepared Rebuttal Testimony of Paul Borkovich in A. 14-06-021.
[7] Envoy subtracts any off-system deliveries from receipts. Net withdrawal equals withdrawals offset by injections, if any. In Envoy, withdrawals are negative numbers while injections are positive numbers.
[8] On low OFO days this interruptible quantity would be cut in half in order to accommodate reasonable intraday increases in scheduled firm withdrawals and in order to incent the nomination of additional flowing supply.

exhaustion of available withdrawal capacity because the normal scheduling process will ensure this.

SoCalGas and SDG&E hope that their proposal to adopt low OFO procedures will be approved by the Commission in 2015. Since we have asked to adopt PG&E's low OFO procedures, it makes sense to also adopt PG&E's high OFO procedures in 2017 and create more statewide consistency. I suggest 2017 rather than 2016 in order to coincide with the added injection capacity that will be provided with the Aliso Canyon Turbine Replacement Project as well as in order to allow SoCalGas and SDG&E to get experience with low OFOs before implementing similar high OFO procedures.

The logic of PG&E's high OFO is similar to that of its low OFO procedures. Whenever transportation customers attempt to inject more supply than is allocated to that daily balancing function, then an OFO will be triggered. Again using the current allocation to balancing, the triggering mechanism for a high OFO would be: If forecasted receipts – forecasted sendout – forecasted net injections into storage accounts > 200 MMcfd, then high OFO. SoCalGas already has a high OFO procedure in place, but that mechanism is based on physical injection capability rather than the injection assets specifically allocated to the daily balancing function. That is, it is this formula: If forecasted receipts – forecasted sendout > total injection capacity, then high OFO. We are proposing to replace that mechanism with this new High OFO procedure because if makes economic sense to allow transportation customers to only balance using the assets they have paid for that purpose. Also, it creates more symmetry with the low OFO process and with PG&E's high OFO process.

At the same time that either a high or low OFO is called, a Stage level is called. The Stage level is set at a level with a noncompliance charge that will be sufficient given the then-current market conditions to incent transportation customers to balance their supplies with their burns. Table 1 below outlines these stages, which correspond to PG&E's.

Table 1: OFO Stages

Stage Level	Tolerance as % of burn	Noncompliance Charge
1	Up to +/- 25%	$.25/dth
2	Up to +/- 20%	$1.00/dth
3	Up to +/- 15%	$5.00/dth
4	Up to +/- 5%	$25.00/dth
5	Up to +/- 5%	$25/dth + citygate
EFO	0%	$50/dth + citygate

A low or a high OFO can be called throughout the year and is not dependent upon storage inventory, unlike SoCalGas and SDG&E's current winter balancing rules. For the reasons described in my low OFO testimony, we are not proposing customer-specific OFOs. A high or low OFO could be called by cycle 2 or cycle 3 for the next flow day A and would remain in place for that flow day. For the day after the OFO flow date, flow day B, there would be no OFO called for cycle 1. This would prevent unnecessary, sustained OFO situations. If, however, those cycle 1 nominations for flow day B show that transportation customers are again using more storage injection or withdrawal than is allocated to the balancing function, then another OFO would be called by cycle 2 or cycle 3 for the flow day B.

We are recommending an increase in the storage assets allocated to the year-round low/high daily balancing functions in order to (1) decrease the frequency of low OFOs to a level seen on PG&E's system and decrease the frequency of high OFOs to a level seen on SoCalGas and SDG&E's system; and (2) increase the tolerances that can be permitted under Stages 1-3. Unless restrained by the maximum tolerance for a given stage level, the specific tolerance levels will be set close to this percentage: (asset allocated to balancing, MMcfd) / forecasted sendout MMcfd.

SoCalGas and SDG&E are proposing that allocations to withdrawal be increased from 340 MMcfd to 525 MMcfd. Using historical data on usage of the balancing function by customers over the April 2013-March 2014 period, we estimate that there would have been at most 23 low OFOs over that period. This is similar to the number of low OFOs that PG&E called on its system over the same period. This is a maximum estimate of the frequency since we believe transportation customers will be incented under this new balancing regime to more closely match their supplies with their burns on a regular, daily basis. Another consideration is that more withdrawal cannot be allocated to the balancing function than 525 MMcfd without doing harm to either the core or the unbundled storage programs, as should be clear later in this testimony (see Table 3).[9]

Similarly, we are proposing that allocations to injection be increased from 200 MMcfd to 345 MMcfd once the Aliso Canyon Turbine Replacement Project comes online. Essentially, we would be allocating all of the incremental capacity of Aliso Canyon to the balancing function to help facilitate the new PG&E-like high OFO procedures. Using historical data on the usage of the balancing function by customers over the April 2013-March 2014 period, we estimate that there would have been at most 43 high OFOs over that period. This is equal to the 3-year average of high OFOs on the SoCalGas system for the years 2011-2013. Again, this is a maximum estimate of the frequency since we believe transportation customers will be incented under this new balancing regime to more closely match their supplies with their burns on a

[9] The withdrawal allocated to the balancing function may not be increased to 525 MMcfd for Q1 of 2016 because withdrawal may have already been sold for the 2015/16 storage season in the G-TBS program. Any unbundled storage withdrawal that has not been sold by the time of a CPUC decision, however, could be allocated to the balancing function for Q1 2016.

regular, daily basis. As before, more injection cannot be allocated to the balancing function than 345 MMcfd without doing harm to either the core or the unbundled storage programs, as should be clear later in this testimony (see Table 3).

One other change is necessary to more closely mirror PG&E's approach to balancing. PG&E provides 5% monthly balancing, rather than 10%. The Utility Reform Network (TURN) has already suggested that SoCalGas and SDG&E move to a 5% monthly balancing regime, and SoCalGas and SDG&E agree with TURN's suggestion.[10] This proposed change is consistent with the philosophy that transportation customers balance their supplies and their burns on a regular, daily basis. SoCalGas and SDG&E are not aware of any other interstate or large utility system allowing the 10% monthly balancing SoCalGas and SDG&E currently provide. This move would also recognize that there is no such thing as negative inventory; whenever monthly imbalances are negative, then transportation customers are basically getting free, involuntary loans of gas from storage customers. A negative 5% monthly tolerance is still not optimal, but it is better than the current negative 10% monthly tolerance. All other aspects of SoCalGas' monthly balancing rules would remain, only the percentage monthly tolerance would change. Unlike today's rules, the core would not be restricted to using a maximum of 83 Bcf of inventory including imbalances since, like other customers, it could use positive 5% monthly imbalances in addition to its storage inventory. The amount of inventory needed for this function then is 5% of maximum monthly October/November demand, which we estimate to be 5 Bcf.

IV. CORE STORAGE ALLOCATIONS

SoCalGas believes the appropriate allocations to the core remain 83 Bcf, 388 MMcfd of firm injection during the summer, and 2,225 MMcfd of withdrawal for the winter period. The 83 Bcf is necessary to bridge the gap between core's 1-35, cold year winter demand and its flowing

[10] Prepared Direct Testimony of Herbert Emmrich on behalf of TURN in A.13-12-013, p.2.

supplies, which would be supported by its winter interstate capacity commitments. (The Commission has approved interstate capacity commitments for the core from 100% "up to" 120% of annual average year core throughput).[11] The 388 MMcfd injection rights are necessary to fill 83 Bcf over 214 injection days. And the 2,225 MMcfd of withdrawal is necessary to bridge the gap between the core's potential winter flowing supplies utilizing 104% of its approved minimum interstate capacity commitments and its 1-35 year peak day demand level. Table 2 below (based on 2016-2019 data from the 2014 CGR) demonstrates these inventory and withdrawal allocations from the prior TCAP period are still appropriate.

Table 2: Core Storage Requirements, MMcf/d per 2014 CGR (2016-2019 Averages)

Annual Average Avg. Temp	104% x Annual Average Winter Flowing Supply	Peak Day	Winter Avg. Cold Year	Withdrawal Peak – winter flow MMcfd	Inventory (1716-1172)x151
1127	1172	3421	1716	**2,249**	**82.2 Bcf**

V. UNBUNDLED STORAGE ALLOCATIONS

Unbundled storage assets are the difference between total system capacities and core/balancing assets. Table 3 below presents my proposed firm capacity allocations to all three storage functions.

Table 3 Storage Capacity Allocations (MMcf/d)

	Bcf	**Withdrawal** Winter	**Withdrawal** Summer	**Injection** 2016 Summer	**Injection** 2017-2019 Summer	**Injection** 2016 Winter	**Injection** 2017-19 Winter
Total	138.1	3175	1812	770	915	390	535
Balancing	5.1	525	525	200	345	200	345
Core	83	2225	1081	388	388	190	190
Unbundled	50	425	206	182	182	0	0

[11] D.04-09-022, mimeo., at p. 88 (Finding of Fact #21).

VI. COSTS OF THE STORAGE FUNCTIONS

Using the same embedded cost methodology that is being used for the currently effective TCAP period, SoCalGas and SDG&E witness Sim-Cheng Fung has estimated a total embedded storage cost of $83.6 million. Ms. Fung then adjusts those costs to reflect final Honor Rancho inventory expansion expenses and the Aliso Canyon Turbine Replacement Project. She recommends establishing the total cost of storage at $96.2 million in 2016 and $110.6 million for 2017-2019.

My testimony addresses how to allocate these costs to the balancing, core and unbundled storage functions. The approach I recommend is consistent with that used by PG&E. Table 4 below applies PG&E's Gas Accord methodology for determining total storage units and allocating embedded storage costs among those storage units.[12] Firm summer injection and "off-cycle" withdrawal units for core and noncore storage are multiplied by 214 days, which is the length of the summer injection season; firm winter withdrawal and "off-cycle" injection units for core and noncore are multiplied by 151 days, the length of the winter season; injection and withdrawal units allocated to the balancing function are multiplied by 365 days since balancing is a year-round service; and then all these dth units of injection/withdrawal service are added to total inventory. Embedded costs are divided by this total dths of firm service capacity to provide a $/dth cost. These costs are then multiplied by the total firm service capacity dths for the three storage services.[13] The results of the cost allocation methodology for 2016-2019 are provided in Table 4:

[12] D.11-04-031, Gas Accord V Settlement Agreement, Appendix A, Tables A-2, A-6; A.09-09-013, Workpapers for Chapter 3, p. WP 3-3, 3-11 to 3-13. This same methodology is continuing into Gas Accord VI.

[13] Details of this analysis are presented in my workpapers in support of this testimony.

Table 4: Costs By Functions

	2016 $MM	2017-2019 $MM
Core	$59.64	$65.73
Balancing	$21.11	$27.83
Unbundled	$15.44	$17.02
Total	**$96.19**	**$110.58**

VII. G-TBS TARIFF

Section 15 in Schedule No. G-TBS is vague, antiquated, and unique in the national storage industry. It states: "Zero-priced, lowest-priority, interruptible injection and withdrawal service shall be included with all sales of inventory, whether that inventory is sold on a stand-alone or package basis." No other storage provider provides free, essentially unlimited interruptible injection and withdrawal rights. In theory a customer with inventory only (a large percentage of the G-TBS sales) could nominate all their gas into or out of their account on one day on a lowest-priority, interruptible basis. Defining the specific quantities of interruptible injection or withdrawal quantities within each inventory-only contract will help both SoCalGas and its counterparties agree on its market value. They have found this difficult with the current vague injection/withdrawal parameters.

Therefore, I propose the following language replace it after March 2016: "Negotiated amounts of lowest-priority, interruptible injection and withdrawal service may be included with inventory sales." This language will allow parties to negotiate on specific, reasonable quantities of such interruptible and withdrawal services. Total "as-available injection rights" for the unbundled storage program would be equal to 319 MMcf/d (50 Bcf inventory divided by 157 days).[14] Total "as-available withdrawal rights" for the unbundled storage program would be equal to 1,136 MMcf/d (50 Bcf inventory divided by 44 days)."[15] The proposed revisions to Schedule No. G-TBS are included in Attachment B to this testimony. Similar allocations of "as-available" rights would be provided to core's 83 Bcf inventory.

VIII. UNBUNDLED STORAGE SHARING MECHANISM

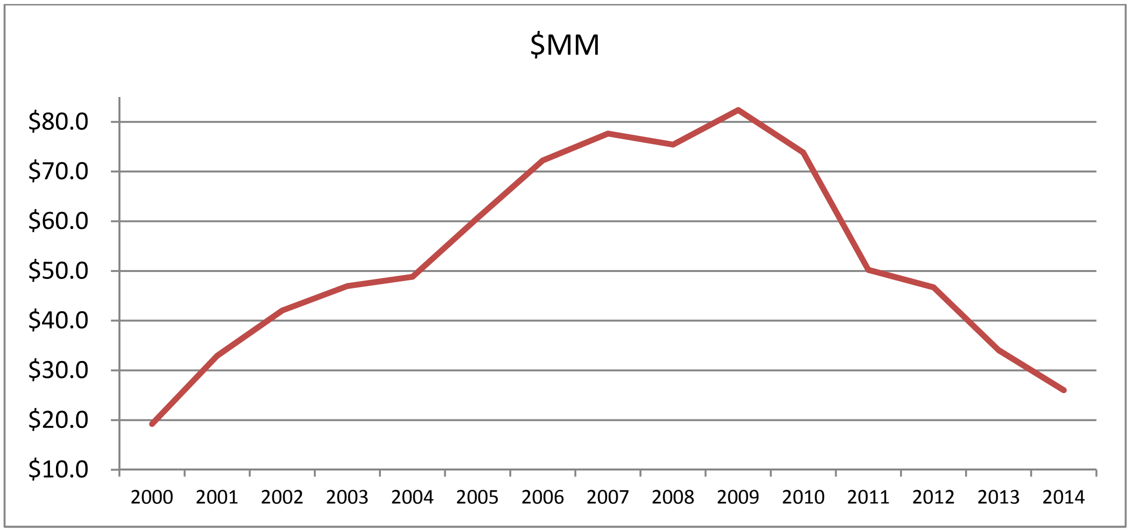
From 1999-2008 the unbundled storage program had a 50/50 sharing mechanism for any revenues relative to costs. As part of the 2009 Phase 1 BCAP Settlement adopted in D. 08-12-020, that mechanism was revised to: 90/10 (customer/shareholder) sharing of the first $15 million of earnings; 75/25 sharing of the next $15 million of earnings; and 50/50 sharing for earnings over $30 million, subject to a $20 million annual shareholder earnings cap. For the next TCAP period we recommend a 60/40 (customer/shareholder) sharing of earnings. The annual shareholder earnings cap of $20 million would remain in place.

Several 2009 BCAP parties advocated the current mechanism because they thought shareholder earnings were too high under the previous 50/50 mechanism after 2005. These high earnings, however, were generated in a totally different natural gas market. SoCalGas' 2000-2014 unbundled storage revenues are shown in Figure 1 below. Natural gas prices are much lower today because of the revolution in gas production technologies in the United States. Natural gas price volatility is much lower today because of significant interstate pipeline investments and slack capacity that give consumers the ability to access that inexpensive gas throughout the year. Significant new storage construction throughout the country has also served to lower winter prices relative to summer prices. As a result, SoCalGas generated just $26

[14] 138 Bcf of inventory divided by 879 MMcf/d (4-year average) of firm injection capacity = 157 days.
[15] 138 Bcf of inventory divided by 3175 MMcf/d of firm withdrawal capacity = 44 days.

million in unbundled storage revenues in 2014. It is unrealistic to believe it will generate significantly more than that with fewer storage assets in the future.

Figure 1: Unbundled Storage Revenues



SoCalGas has operated in the 90/10 range for the last two years. Average annual shareholder pre-tax earnings for the last two years have been just three hundred thousand dollars. Quite simply, this does not provide enough incentive for SoCalGas to creatively and aggressively market its asset, to the ultimate benefit of customers. If SoCalGas is only going to earn 10% of a few million dollars of net revenues, a better alternative for the shareholder is to give all the revenues to customers (100% balancing) and then cut the resources currently involved with marketing and managing unbundled storage. The 100% shareholder cost-saving benefit of cutting marketing, analytical, and back office staff exceeds the value of today's sharing mechanism in today's storage market. SoCalGas could simply offer a single bundled product in a one-time auction each year and not devote any further resources to the endeavor.

The proposed sharing mechanism, however, is better for customers because high sharing percentages for the shareholder result in higher total revenues. The Commission has recognized this in many other sharing mechanisms. Both the Montebello salvage operation and the Native

Gas programs operate under 50/50 sharing mechanism. When shareholders share in a meaningful percentage of the gains, the company has a strong incentive to maximize salvage value or native gas production.

The benefits that customers may obtain from better aligning the incentives of the customers with the incentives of the shareholders in the unbundled storage program can be great. Assume the cost target for unbundled storage is $26 million. If, as has been the case with SoCalGas during the last several years, the program continues under a 90/10 mechanism, the revenues will likely continue to be just a few million dollars over costs. The customer benefit of $4 million profits (assuming $30 million in revenues) is $3.6 million. With stronger financial incentives SoCalGas could dedicate greater time and resources to market storage. If SoCalGas increases revenues by 15%, to $34.5 million, the profit increases to $8.5 million of profits. The customers under this hypothetical scenario are better off than under the 90/10 regime because they receive $5.1 million (60% of $8.5 million earnings) rather than $3.6 million.

The very high shareholder earnings that SoCalGas realized in previous, stronger storage markets using the 50/50 sharing mechanism would not reoccur. At the same time, SoCalGas would have a strong incentive to maximize unbundled storage revenues—primarily to the benefit of customers.

IX. POSTING REQUIREMENT

As part of D.07-12-019 (the Omnibus Decision), SoCalGas agreed to post primary unbundled storage transaction details on its Envoy system the day after a deal was executed. That requirement was carried over into the 2009 BCAP. SoCalGas, however, believes it is time to revisit and eliminate that requirement. SoCalGas has repeatedly noted that PG&E and Northern California storage fields do not post their storage transaction details. Some interveners have argued for such a requirement since "SoCalGas was the only storage provider in Southern California." Without rehashing all the past arguments made on this issue, it should now be obvious that SoCalGas does not have the ability to manipulate prices in the unbundled storage market. If it did, it would be able to generate much greater revenues than it has. Since SoCalGas is only able to charge its unbundled storage customers the price they feel is warranted for a particular storage product, the posting of the prices paid by other parties for other products at other times is unnecessary. Therefore, SoCalGas proposes that this unique posting requirement be eliminated.

X. ALISO CANYON AND IN-KIND FUEL

As explained in my 2009 BCAP testimony,[16] the electricity costs associated with the Aliso Canyon Turbine Replacement Project should also be recovered from the storage in-kind fuel factor described above through the following mechanism:

Electricity costs ÷ Gas Daily S. Calif. Border price = Equivalent Gas Compressor Fuel.

This "equivalent gas compressor fuel volume" should be added to actual gas compressor fuel to develop both the annually-adjusted in-kind storage fuel factor. SoCalGas' System Operator will sell this "equivalent gas" volume in the marketplace in order to pay for the electricity costs of the electric compressors in the storage fields.[17]

XI. INFORMATION SYSTEM MODIFICATIONS AND COSTS

Information system enhancements are required to be made to both SoCalGas Envoy and the Special Contract Billing System to implement high OFO requirements for SoCalGas customers. Much of the implementation can be leveraged off of the Low OFO implementation. The cost of these enhancements is estimated to be less than $1.7 million.

---

[16] Prepared Direct Testimony of Steve Watson on Phase II Issues in A. 08-02-001 at p. 3-4.
[17] This proposal was adopted in the previous BCAP, but the Aliso Canyon Turbine Replacement Project will not come on-line until the end of 2016.

XII. QUALIFICATIONS

My name is Steve Watson. I am employed by SoCalGas as the Capacity Products Staff Manager. My business address is 555 West Fifth Street, Los Angeles, California, 90013-1011. I received a Bachelor's degree in History and International Relations from the University of California, Davis, and a Master's Degree in Public Policy from the University of California, Berkeley. I have been employed by SoCalGas since 1986. I have worked in Gas Supply, Customer Services, the Strategic Planning and Transmission Capacity Planning Departments. I am currently the Capacity Products Staff Manager, responsible for staff support to our Pipeline Products Manager and Storage Products Manager. Before joining SoCalGas I worked as a natural gas analyst at the Department of Energy.

I have previously testified before this Commission.

This concludes my prepared direct testimony.

ATTACHMENT A

Application No: A.14-06-
Exhibit No.:
Witness: Steve Watson

Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) for Low Operational Flow Order and Emergency Flow Order Requirements	))))))	A.14-06- (Filed June 27, 2014)

PREPARED DIRECT TESTIMONY OF

STEVE WATSON

SOUTHERN CALIFORNIA GAS COMPANY AND

SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

June 27, 2014

TABLE OF CONTENTS

PREPARED DIRECT TESTIMONY

OF STEVE WATSON

I. PURPOSE

The purpose of my direct testimony on behalf of Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) is to propose the replacement of SoCalGas and SDG&E's winter balancing rules with low Operational Flow Order (OFO) and Emergency Flow Order (EFO) requirements similar to those instituted by Pacific Gas and Electric Company (PG&E).

II. LIMITATIONS OF EXISTING WINTER BALANCING RULES

In December 2013 and again in February 2014, SoCalGas and SDG&E had to curtail standby procurement service.[1] During the February period, SoCalGas and SDG&E had to go further and institute emergency curtailment of electric generation (EG) customers on February 6 and 7. Despite that emergency curtailment of end-use EG load, the California Independent System Operator (CAISO) had to call a FlexAlert. Prior to curtailing standby procurement service, SoCalGas and SDG&E were operating under their winter balancing, 5-day/50% balancing rules.[2] Under this regime, marketers, suppliers, and customers were able to profitably divert flowing supply to higher-value markets that were being affected by abnormally cold weather.[3] In both December 2013 and February 2014, this diversion of flowing supply led to over-reliance on storage withdrawals and pipeline draft to meet demand.[4] In both cases, in order to avoid widespread end-use customer curtailments, SoCalGas had to curtail standby

[1] The curtailment of standby procurement service occurred between December 6-11, 2013, and February 6-10, 2014.
[2] *See* SoCalGas Rule 30, Section G.
[3] Slides 6 and 12 from attached Customer Forum Presentation (Attachment A) shows the abnormally cold conditions. Slides 7-9, 13-15 show the drops in flowing supply receipts and the price spikes in other parts of the country.
[4] Slides 19-22 from the attached Customer Forum Presentation (Attachment A) illustrate this.

procurement service. These curtailments eventually have $100/dth noncompliance charges plus a standby procurement charge (150% of the highest SoCalGas border price index) for marketing agents who underdelivered by more than -10% of their customers' burn.

III. PROPOSED LOW OPERATIONAL FLOW ORDER

With the recent experience of December 2013 and February 2014, SoCalGas and SDG&E believe it is time to replace their winter balancing rules, which were instituted in 1998, with low OFO and EFO procedures similar to those on the PG&E system. SoCalGas and SDG&E believe the new low OFO and EFO procedures will minimize supply-related curtailment threats by ensuring that transportation customers do not use any more storage withdrawal than has been allocated for the purpose of balancing. The overuse of withdrawal for transportation balancing can jeopardize system reliability by exhausting SoCalGas' total withdrawal capability. As proposed by Ms. Musich, these new rules would become effective starting in January 2015. SoCalGas and SDG&E are not proposing in this Application to change its current high OFO procedures, even though those are different from PG&E's procedures. In addition, if both utilities had low OFO/EFO authority similar to PG&E's, SoCalGas and SDG&E could also eliminate the standby procurement curtailment step in its curtailment Rule 23 and Rule 14, respectively.

IV. PG&E LOW OFO PROCESS

PG&E's low OFO procedures are described in its Rule 14. Under its procedures, whenever PG&E forecasts that the next gas day's pipeline inventory (pack) will fall below 3,900 MMcf,[5] it can call a Stage 1 through Stage 5 OFO for the next gas day.[6] This "trigger" indicates that PG&E has used all the assets it has dedicated to the balancing function — 75 MMcfd of

[5] 4,000 MMcf if forecast demand exceeds 2,800 MMcf.
[6] It attempts to do this at least 12 hours before the next gas day.

storage withdrawal plus several hundred MMcf of pipeline draft.[7] Contrary to SoCalGas and SDG&E's current rules, PG&E does not use any more storage withdrawal for the balancing function than specifically allocated to that function.[8] Therefore, on the PG&E system, any underdeliveries not met with customer-specific storage withdrawals or the 75 MMcfd of storage withdrawal dedicated to the balancing function will result in a reduction in pipeline inventory (draft).

PG&E has wide discretion as to what stage low inventory OFO it calls for the next day. Table 1 below summarizes PG&E's low system-wide, OFO experience.

Table 1

Stage	Tolerance	Average Tolerance	Noncompliance Charge	#OFOs (2012-3/31/2014)
1	Up to -25%	-6%	$0.25/dth	22
2	Up to -20%	-7%	$1.00/dth	6
3	Up to -15%	-5%	$5.00/dth	4
4	Up to -5%	-5%	$25.00/dth	4
5	Up to -5%	n/a	$25.00/dth plus citygate	0
EFO	0%	0%	$50/dth plus citygate	0

A. Advantages of PG&E-like low OFO process vis-à-vis SoCalGas and SDG&E winter balancing rules

[7] The draft capability would be the prior day's pipeline inventory minus the 3,900 MMcf trigger. Theoretically, this could be as high as 400 MMcfd or as low as zero.
[8] Under the 5-day, 50% balancing rule SoCalGas will often use more than 1 Bcfd of storage withdrawal for balancing low deliveries even though it has only 340 MMcfd allocated to the balancing function.

One advantage of the PG&E low OFO approach is that it gives the operator the ability to institute tighter tolerances, when necessary, at almost any time during the winter. Under its winter balancing rules, however, SoCalGas and SDG&E are constrained to 5-day, 50% balancing for over 90% of its winter days. When inventories reach peak day + 20 Bcf, SoCalGas and SDG&E can implement 70% daily balancing, but all of PG&E's stages allow tighter tolerances than this. A second advantage of the PG&E low OFO approach is that it can be instituted at the beginning of any flow day throughout the year, not just during the winter. Higher and more volatile EG demands may require low OFOs during the summer, as well as during the winter.

An additional advantage of the PG&E approach from a customers' perspective is that the noncompliance charges for low OFOs are less onerous than the noncompliance charges that SoCalGas and SDG&E use when they curtail standby procurement. Pursuant to SoCalGas Rule 23 and SDG&E Rule 14, SoCalGas and SDG&E charge $100/dth after hour 8 for violations of standby procurement plus standby procurement charges. Under PG&E's low OFO procedures, customers are charged a maximum of $25/dth. Another customer advantage of the PG&E approach is that it reduces the likelihood of end-use curtailment. While SoCalGas experienced transportation service curtailments in February 2014, PG&E got through the February period using Stage 4 low OFOs for February 6-8, without any curtailments. Under its low OFO procedures, PG&E may be inclined to call the low OFOs sooner than SoCalGas and SDG&E would curtail standby procurement because the former does not create as much market shock as does the latter. The sooner customers closely align their supplies with their burns, the less likely that operational issues develop that will necessitate the utility having to curtail end-use demand because of inadequate supply.

B. Disadvantage of the PG&E low OFO Approach

With respect to SoCalGas and SDG&E, the disadvantage of the PG&E OFO approach is that it relies on up to 600 MMcf of pipeline pack/draft capability in its triggering mechanism. SoCalGas and SDG&E have only a third of such pack/draft capability and are unable to use this capability in either a high OFO or a low OFO triggering procedure. This inability was affirmed by the Commission over the protests of Shell Energy in D.09-11-006. Fortunately, SoCalGas and SDG&E can adopt PG&E's low OFO procedures without using linepack in the trigger calculation, as further explained in Section V below.

V. SOCALGAS AND SDG&E LOW OFO PROPOSAL

PG&E triggers a low OFO when it forecasts its 75 MMcfd of storage withdrawal allocated to balancing and its available draft (subject to the minimum 3,900 MMcf inventory figure) will be exhausted.[9] SoCalGas and SDG&E propose to trigger a low OFO when they forecast that the 340 MMcfd of storage withdrawal allocated to balancing will be exhausted. If forecast receipts – forecast sendout – forecast withdrawal scheduled from storage accounts (negative number) < - 340 MMcfd, then a low OFO is called. SoCalGas and SDG&E's limited drafting capability is excluded from the triggering mechanism.

SoCalGas currently has in its Envoy system under the Public Page, "Informational Postings," "Operations," "Daily Operations Tab" a line labeled "storage injection (withdrawal) for customer balancing" that shows how much storage withdrawal was actually used for the balancing function and how much is forecast to be used for the following days.[10] The forecasted number represents forecasted physical withdrawal minus recent withdrawal nominations from storage accounts — that is, storage withdrawal being used for the balancing function. In order to

[9] PG&E is proposing to allocate 200 MMcfd of storage withdrawal to the balancing function in its next Gas Accord. PG&E A.13-12-012, pp. 10-48 through 10-50.
[10] *See* example of this current Envoy posting in Attachment B.

improve market transparency and forecasting accuracy, SoCalGas would post the elements of this calculation on Envoy several times each day.[11] Also, SoCalGas and SDG&E would propose to call a low OFO by 5 A.M, Pacific time, in time for cycle 3 scheduling on flow day.

SoCalGas and SDG&E are proposing OFO stages and an EFO stage exactly like those in PG&E's system. The stages are presented in Table 2 below. The stage level called by SoCalGas and SDG&E would depend on the level of noncompliance charge level that the utilities believe necessary to incent customers/suppliers to more closely match supply and demand.[12] SoCalGas and SDG&E will not provide tolerances greater than those permitted with 340 MMcfd of withdrawal capacity.

Table 2

Stage	Tolerance	Noncompliance Charge
1	Up to -25%	$0.25/dth
2	Up to -20%	$1/dth
3	Up to -15%	$5.00/dth
4	Up to -5%	$25.00/dth
5	Up to -5%	$25/dth plus daily balancing standby rate[13]
EFO	Zero	$50/dth plus daily balancing standby rate

Looking back on the experience in December 2013 and February 2014, had SoCalGas and SDG&E possessed this authority, a low OFO day would have been called for December 5

[11] *See* illustrative example of informational postings in Attachment C.
[12] Market conditions such as those in December 2013 or February 2014 would certainly demand a Stage 3 or Stage 4 OFO because of the price spikes for natural gas in other parts of the country over those periods.
[13] This rate is described in the testimony of Mr. Borkovich. It is the *higher of* SCG Citygate, PG&E Citygate, EP-Permian, EP-SJ Bondad, or Opal Plant Tailgate.

and 6 and might have helped avoid the standby procurement curtailment called for December 6.[14] Two more low OFO days would have been called for February 1 and February 6.[15]

VI. RELATED ISSUES

A. Emergency OFOs

Except for an unusual circumstance during bankruptcy, PG&E has not had to use EFO procedures, and SoCalGas and SDG&E do not envision calling an EFO on its system either, as long as the noncompliance charges for OFO Stages 4 and 5 are sufficiently high. SoCalGas and SDG&E believe that their noncompliance charges for OFO Stages 4 and 5 as presented in Table 2 are sufficiently high. Nevertheless, like PG&E, SoCalGas and SDG&E could invoke EFOs when they forecast or actually experience a supply and/or capacity shortage that threatens deliveries to end-use customers.

B. Interruptible withdrawal on low OFO days

SoCalGas and SDG&E believe that some level of interruptible withdrawal can be used to meet the delivery tolerances specified in a low OFO. The maximum quantity of interruptible rights that could be scheduled on low OFO days would be: 50% x (Withdrawal Capacity - Firm storage withdrawal nominations – 340 MMcfd). The 50% factor will ensure that withdrawal limits are not reached and that increases in supply to match burns have a mix of storage and flowing supply in order to maintain system reliability. It would also allow firm withdrawal customers to increase their intraday cycle nominations without being unduly restricted by elapsed pro rata rules for any previously scheduled interruptible withdrawals.

---

[14] *See* Attachment A, Slide 21.
[15] *See* Attachment A, Slide 19.

C. No Customer-Specific Low OFOs

In its Rule 14, PG&E has rules for customer-specific, as opposed to system-wide, low OFOs. These specific rules are seldom used, however, and are often ineffective when used.[16] This has certainly been SoCalGas and SDG&E's experience with customer-specific high OFOs. Therefore, the utilities are not proposing customer-specific low OFOs at this time.

D. Storage Assets Allocated to Balancing

The frequency of OFOs under the PG&E approach is related to the size of the assets allocated to the balancing function. From April 1, 2013, to March 31, 2014, PG&E had 24 low OFOs. Assuming a 340 MMcfd trigger for low OFOs and assuming that actual balancing activity was forecasted accurately, SoCalGas estimates that it would have had 41 low OFOs over that same period.[17] This likely overstates the frequency of low OFOs since customers will likely use more storage or schedule more out-of-state supplies under SoCalGas' new, PG&E-like balancing regime.

The assets allocated to the balancing function on SoCalGas' system are currently set through the year 2015.[18] However, in the future, SoCalGas would be amenable to considering an increase to its balancing assets. An increase in storage withdrawal allocated to the balancing function could decrease the frequency of OFOs.[19] In addition, allocating more withdrawal to the balancing function would allow wider tolerances to be accommodated when a low OFO was

---

[16] Any specific customer with an "imbalance" can trade their "imbalance" to a non-targeted customer, resulting in the continued drafting of pipeline inventory. Almost half the time PG&E's customer-specific OFOs are followed by system-wide OFOs the next day. And often those customer-specific OFOs involve 8-9 very large marketers rather than just 1-2 specific customers.

[17] *See* Spreadsheet Attachment D.

[18] D.09-11-006, D.14-06-007.

[19] From April 1, 2013 to March 31, 2014, SoCalGas would have had the same number of OFOs, 24, that PG&E experienced, if it had 500 MMcfd of withdrawal allocated to the balancing function. *See* Spreadsheet Attachment D.

called. PG&E has requested in its pending Gas Accord to allocate more storage withdrawal (200 MMcfd/d rather than 75 MMcfd/d) to its balancing function.[20]

VII. QUALIFICATIONS

My name is Steve Watson. I am employed by SoCalGas as the Capacity Products Staff Manager. My business address is 555 West Fifth Street, Los Angeles, California, 90013-1011. I received a Bachelor's degree in History and International Relations from the University of California, Davis, and a Master's Degree in Public Policy from the University of California, Berkeley. I have been employed by SoCalGas since 1986. I have worked in Gas Supply, Customer Services, the Strategic Planning and Transmission Capacity Planning Departments. I am currently the Capacity Products Staff Manager, responsible for staff support to our Pipeline Products Manager and Storage Products Manager. Before joining SoCalGas I worked as a natural gas analyst at the Department of Energy.

I have previously testified before the California Public Utilities Commission.

This concludes my prepared direct testimony.

[20] PG&E A.13-12-012, pp. 10-48 through 10-50.

Attachment A

2014 Customer Forum

May 8, 2014

Southern California Gas Company
A Sempra Energy utility®

Glad to be of service.®

Agenda

- Introductions
- Antitrust Disclaimer
- Curtailment Events
  - December 2013 Curtailment
  - February 2014 Curtailment
- Low OFO Proposal
- Review of April 2013 to March 2014
  - Minimum Flow Requirements
  - Southern System Requests
- High OFO Review
- Additional Tools/System Improvements
- Electric – Gas Coordination
- Post Forum Report to be filed no later than July 7, 2014

AMERICAN GAS ASSOCIATION
ANTITRUST COMPLIANCE GUIDELINES

Introduction

The American Gas Association and its member companies are committed to full compliance with all laws and regulations, and to maintaining the highest ethical standards in the way we conduct our operations and activities. Our commitment includes strict compliance with federal and state antitrust laws, which are designed to protect this country's free competitive economy.

Responsibility for Antitrust Compliance

Compliance with the antitrust laws is a serious business. Antitrust violations may result in heavy fines for corporations, and in fines and even imprisonment for individuals. While the General Counsel's Office provides guidance on antitrust matters, you bear the ultimate responsibility for assuring that your actions and the actions of any of those under your direction comply with the antitrust laws.

Antitrust Guidelines

In all AGA operations and activities, you must avoid any discussions or conduct that might violate the antitrust laws or even raise an appearance of impropriety. The following guidelines will help you do that:

- ***Do*** consult counsel about any documents that touch on sensitive antitrust subjects such as pricing, market allocations, refusals to deal with any company, and the like.

- ***Do*** consult with counsel on any non-routine correspondence that requests an AGA member company to participate in projects or programs, submit data for such activities, or otherwise join other member companies in AGA actions.

- ***Do*** use an agenda and take accurate minutes at every meeting. Have counsel review the agenda and minutes before they are put into final form and circulated and request counsel to attend meetings where sensitive antitrust subjects may arise.

- ***Do*** provide these guidelines to all meeting participants.

- ***Do not, without prior review by counsel,*** have discussions with other member companies about:

  - your company's prices for products, assets or services, or prices charged by your competitors
  - costs, discounts, terms of sale, profit margins or anything else that might affect those prices
  - the resale prices your customers should charge for products or assets you sell them
  - allocating markets, customers, territories products or assets with your competitors
  - limiting production
  - whether or not to deal with any other company
  - any competitively sensitive information concerning your own company or a competitor's.

- ***Do not*** stay at a meeting, or any other gathering, if those kinds of discussions are taking place.

- ***Do not*** discuss any other sensitive antitrust subjects (such as price discrimination, reciprocal dealing, or exclusive dealing agreements) without first consulting counsel.

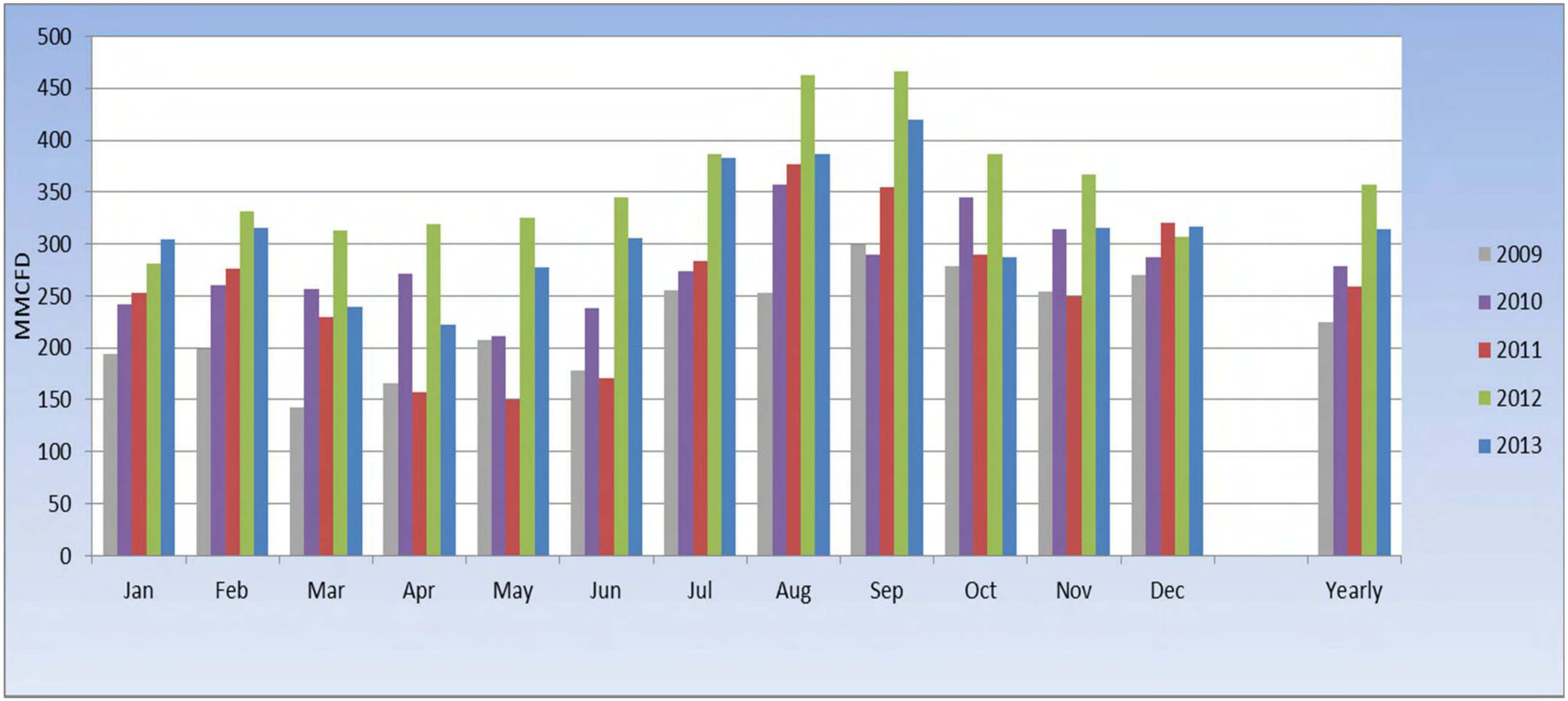
- ***Do not*** create any documents or other records that might be misinterpreted to suggest that AGA condones or is involved in anticompetitive behavior.

We're Here to Help

Whenever you have any question about whether particular AGA activities might raise antitrust concerns, contact the General Counsel's Office, Ph: (202) 824-7072; E-mail: GCO@aga.org, or your legal counsel.

American Gas Association
Office of General Counsel
Issued: December 1997
Revised: December 2008

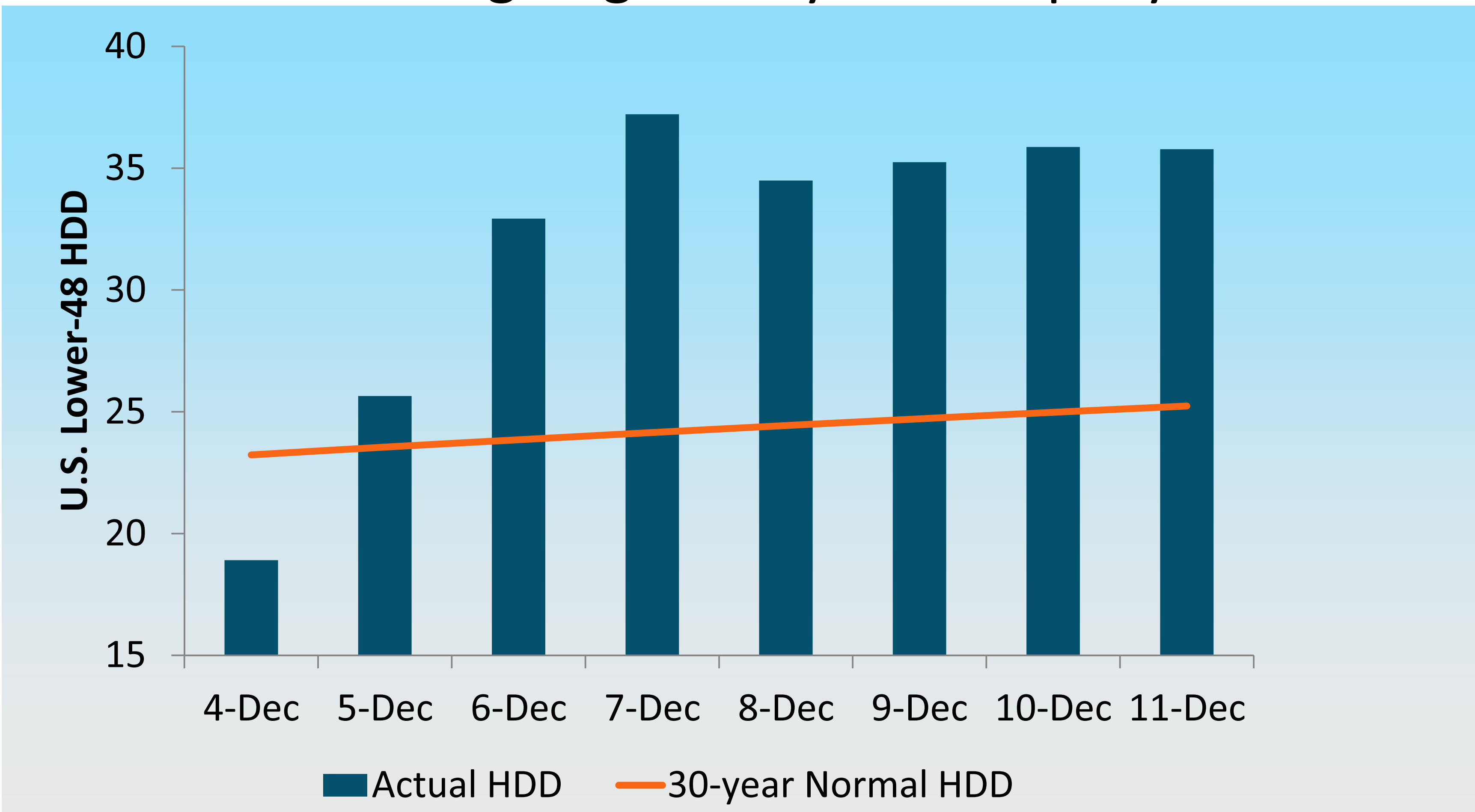
SoCalGas/SDG&E Southern System EG Daily Average Has Increased Post-SONGS



December 2013 Curtailment

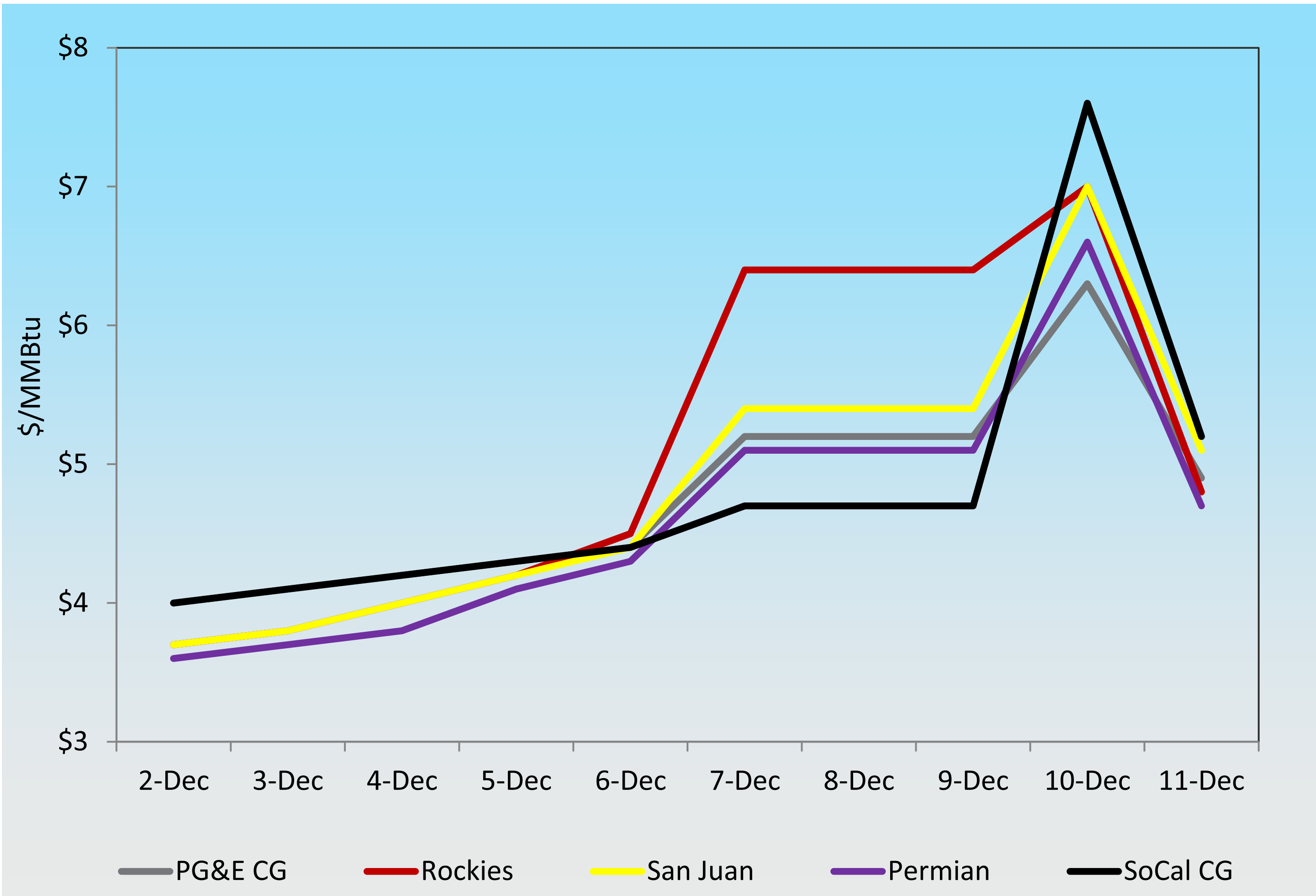
- December 5
  - Gas prices east of California (EOC) begin to rise above SoCalGas border as Winter Storm Cleon starts hitting the western US
- December 6
  - As prices continue to rise EOC, customer deliveries into SoCalGas are 1.6 BCF with a sendout of 4.4 BCF and SoCalGas calls for curtailment of standby service
- December 6-11
  - Cold weather blankets southern California with high core loads as well as high EG utilization
- December 9-10
  - Gas Control works closely with CAISO to move the EG load off of the severely taxed SDG&E and LA basin plants to areas that are closer to the storage fields
  - SoCalGas and SDG&E call for conservation of both gas and electric

Nationally, from December 4th to the 7th Heating Degree Days rose rapidly

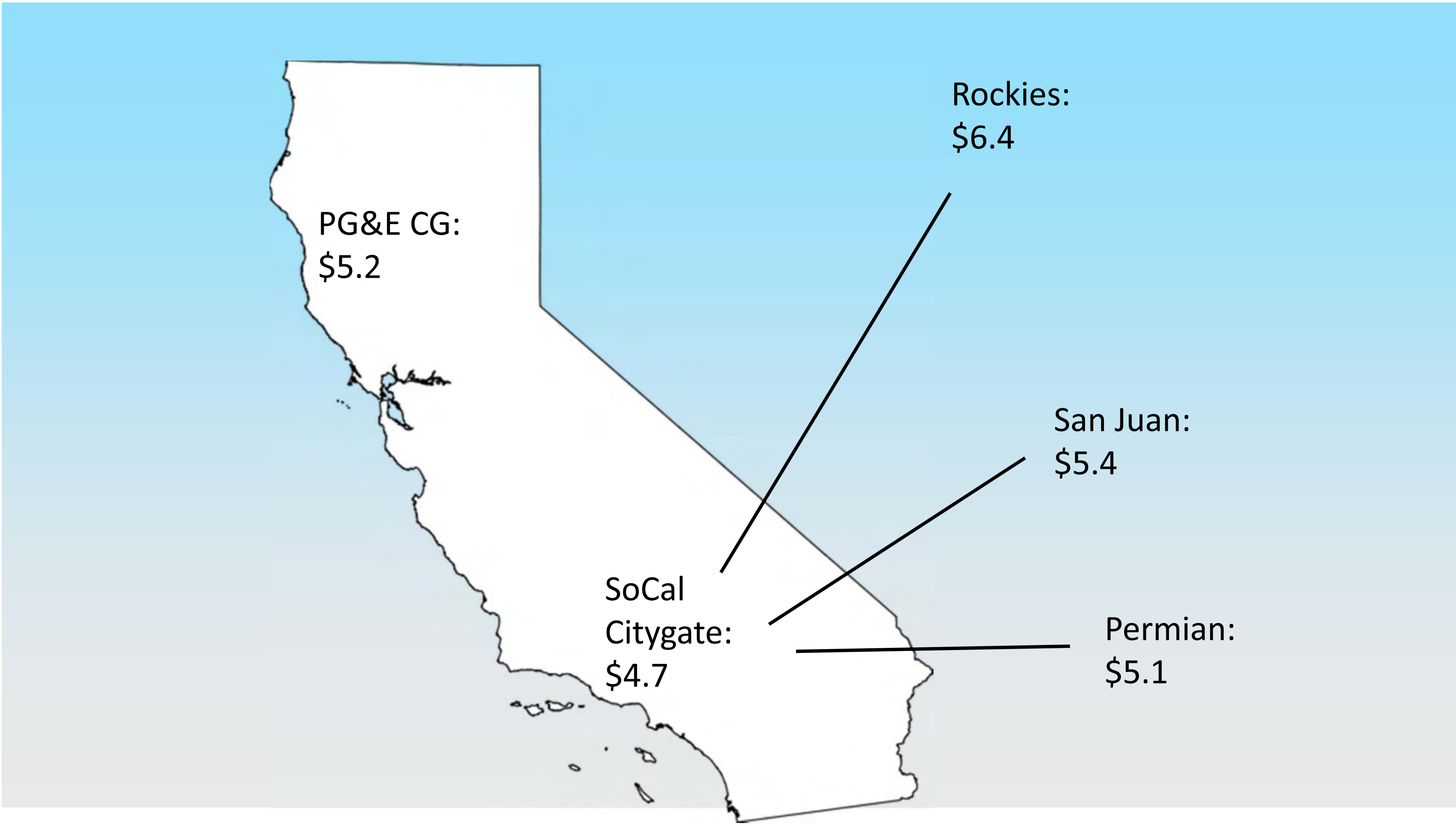


Source: Thomson Reuters

By Dec 6th, Marketers had already begun diverting supplies to higher-valued markets east of California

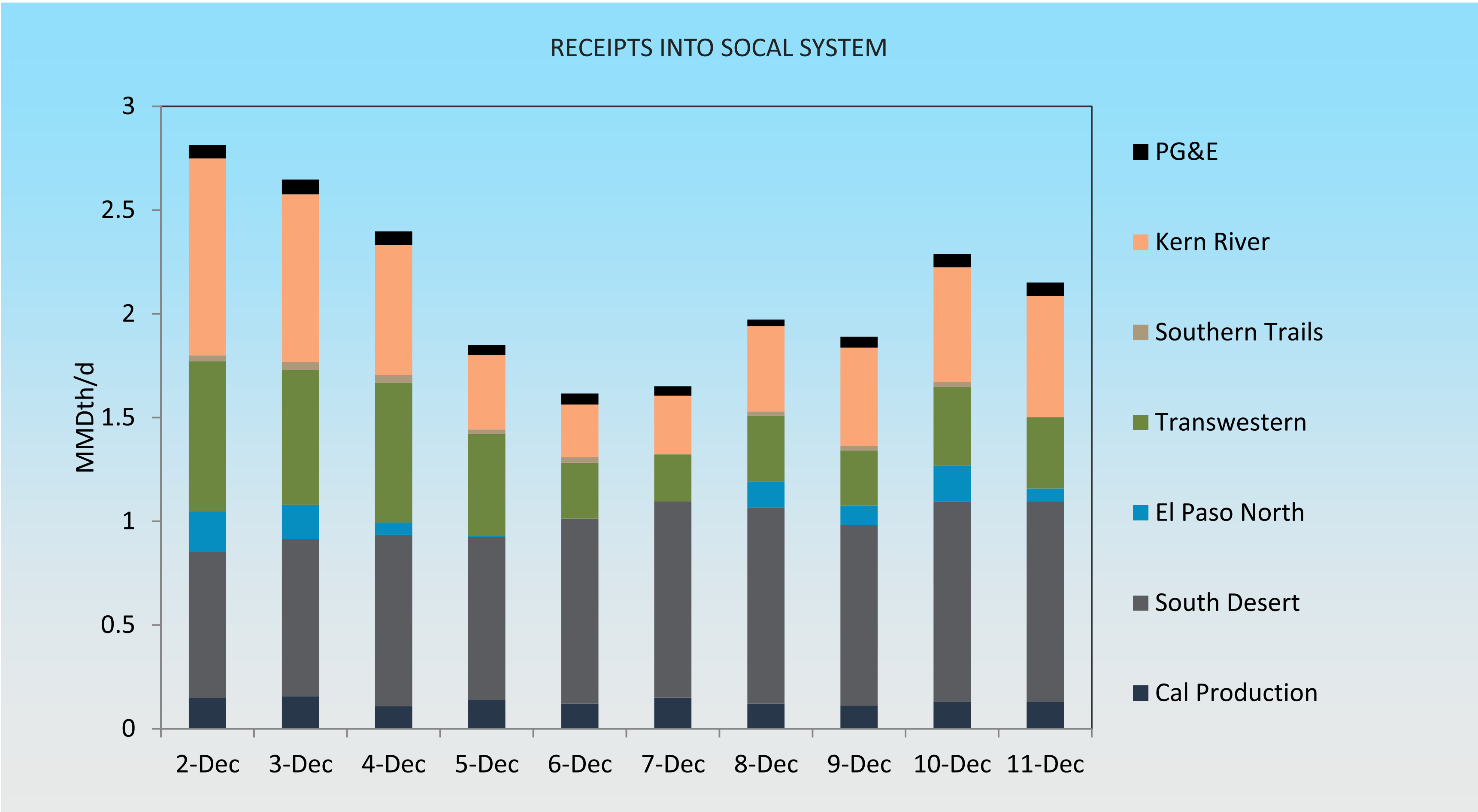


Dec 7, 2013 Gas Prices



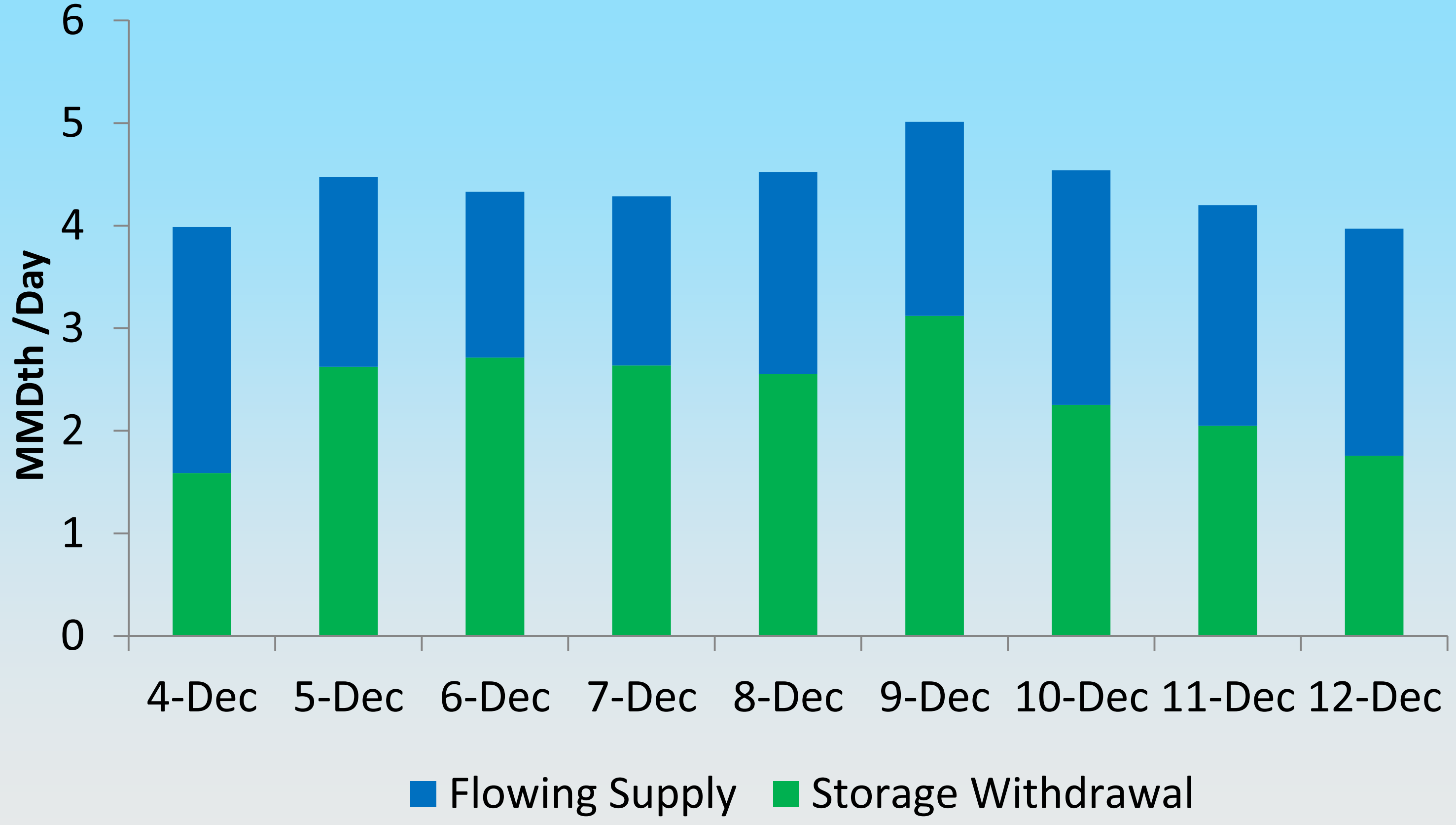
$/MMBtu

Receipts decline as prices spike elsewhere – Dec. 2013



Source: Envoy Daily Operations

Withdrawal Peaked at 62% of Send Out



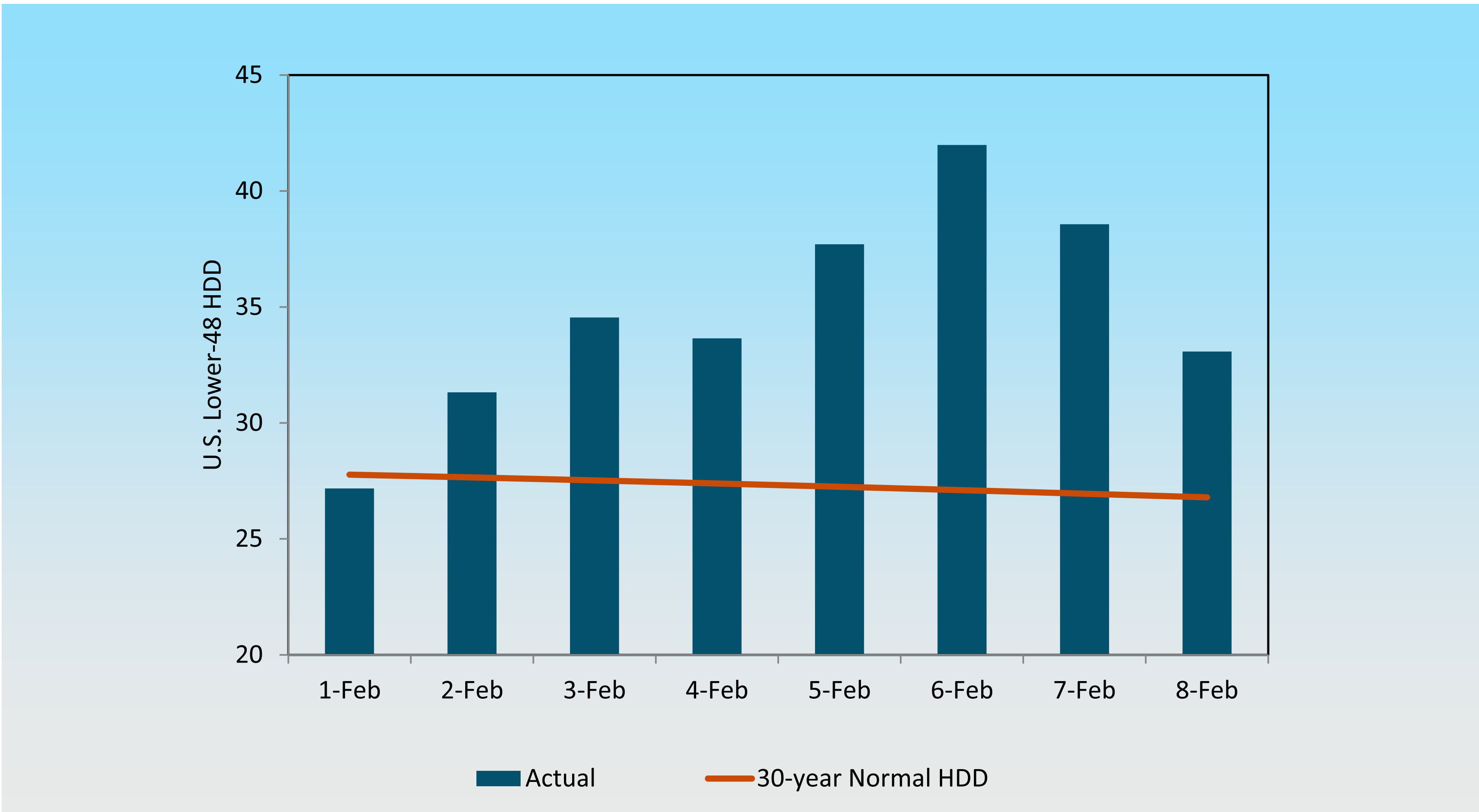
Source: ENVOY Daily Operations

February 2014 Curtailment

February 4-10

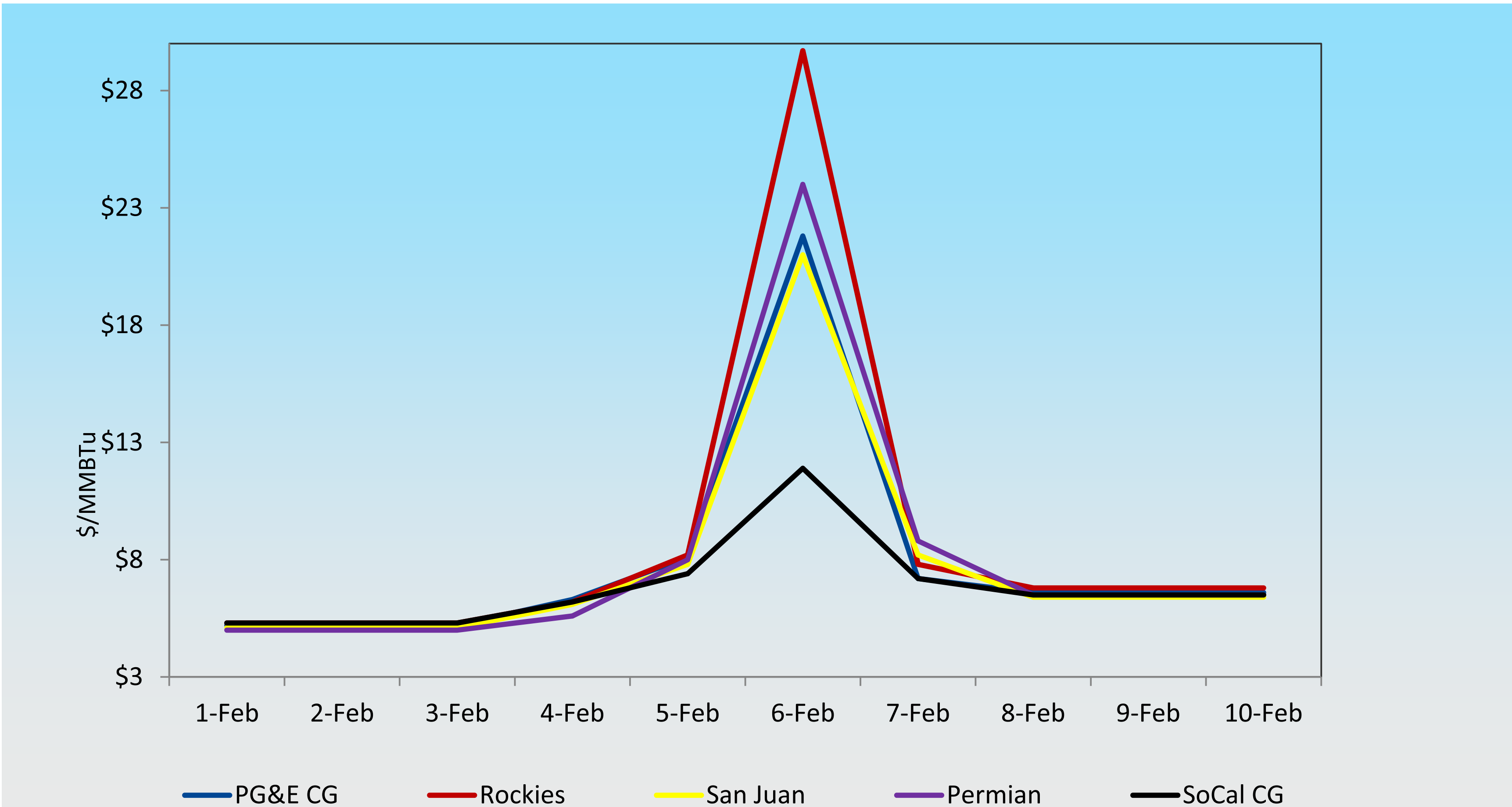
- Average temperature in the lower 48 states fell significantly below normal
- High demand outside California created negative spreads between Southern California and upstream supply zones causing receipts into the SoCalGas system to fall
- In California gas demand for power generation was also boosted by outages in Diablo Canyon units 1 and 2
- **February 6**
- SoCalGas and SDG&E issued an emergency localized curtailment for electric generation customers
- Curtailment of Standby Service called
- SoCalGas worked with CAISO and LADWP to cut and shift load to other areas
- CAISO issues a FlexAlert

Nationally, from February 1st to the 6th Heating Degree Days rose rapidly

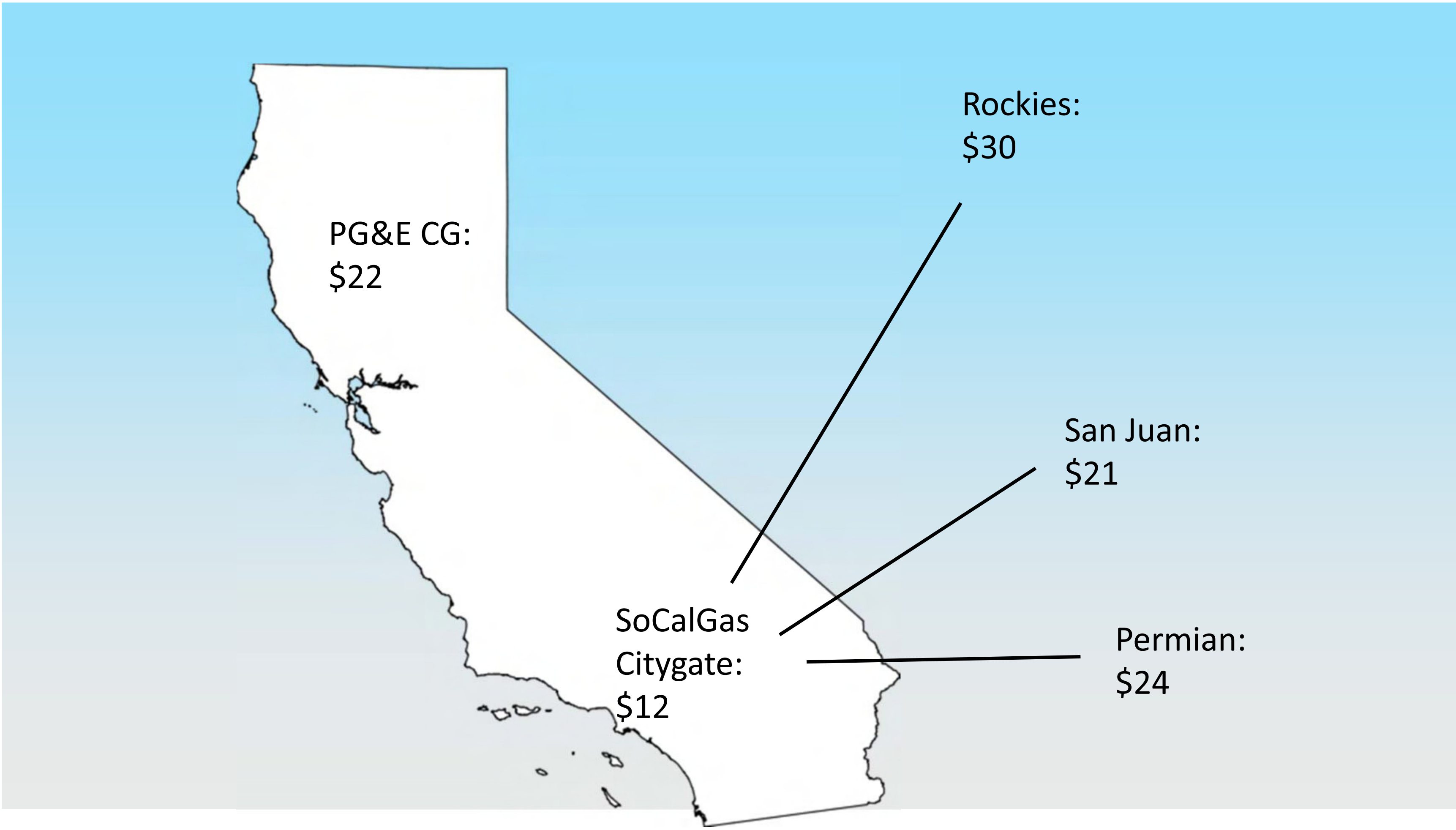


Source: Thomson Reuters

By Feb 5th, marketers had begun diverting supplies to Higher-Valued Markets east of California

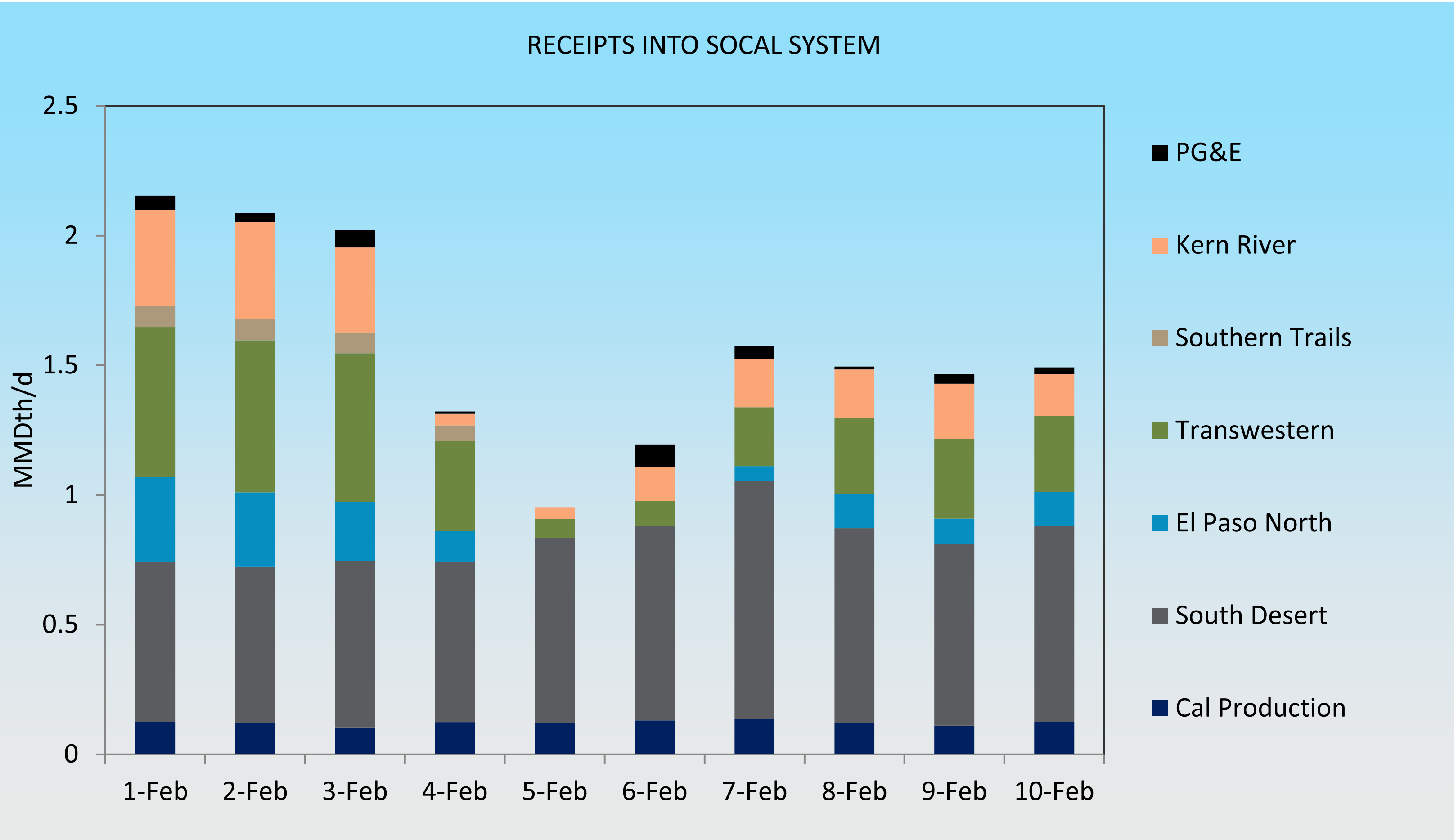


Feb 6, 2014 Gas Prices



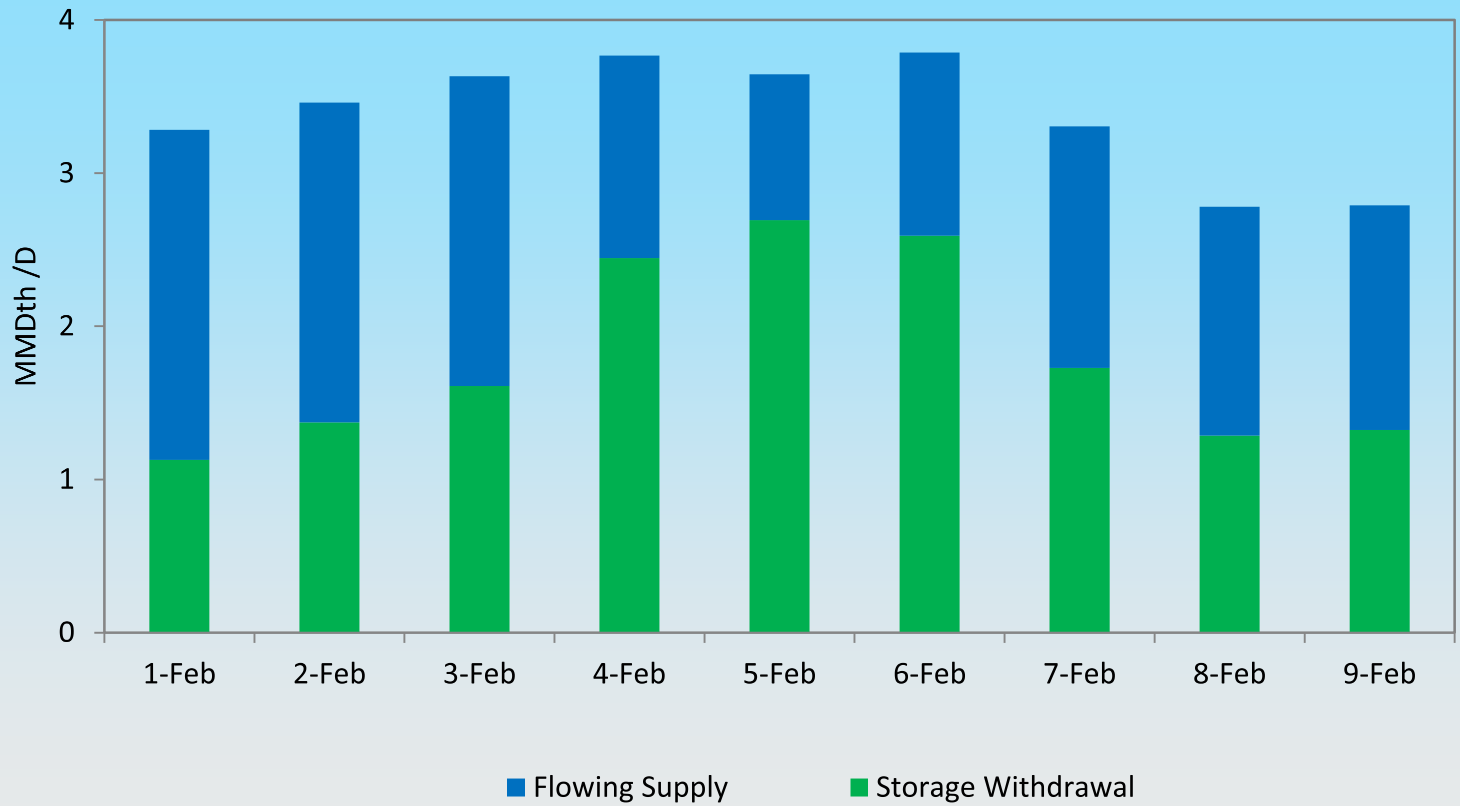
$/MMBtu

Receipts decline as prices spike elsewhere - Feb. 2014



Source: Envoy Daily Operations

Withdrawal Peaked at 73% of Send Out



Source: ENVOY Daily Operations

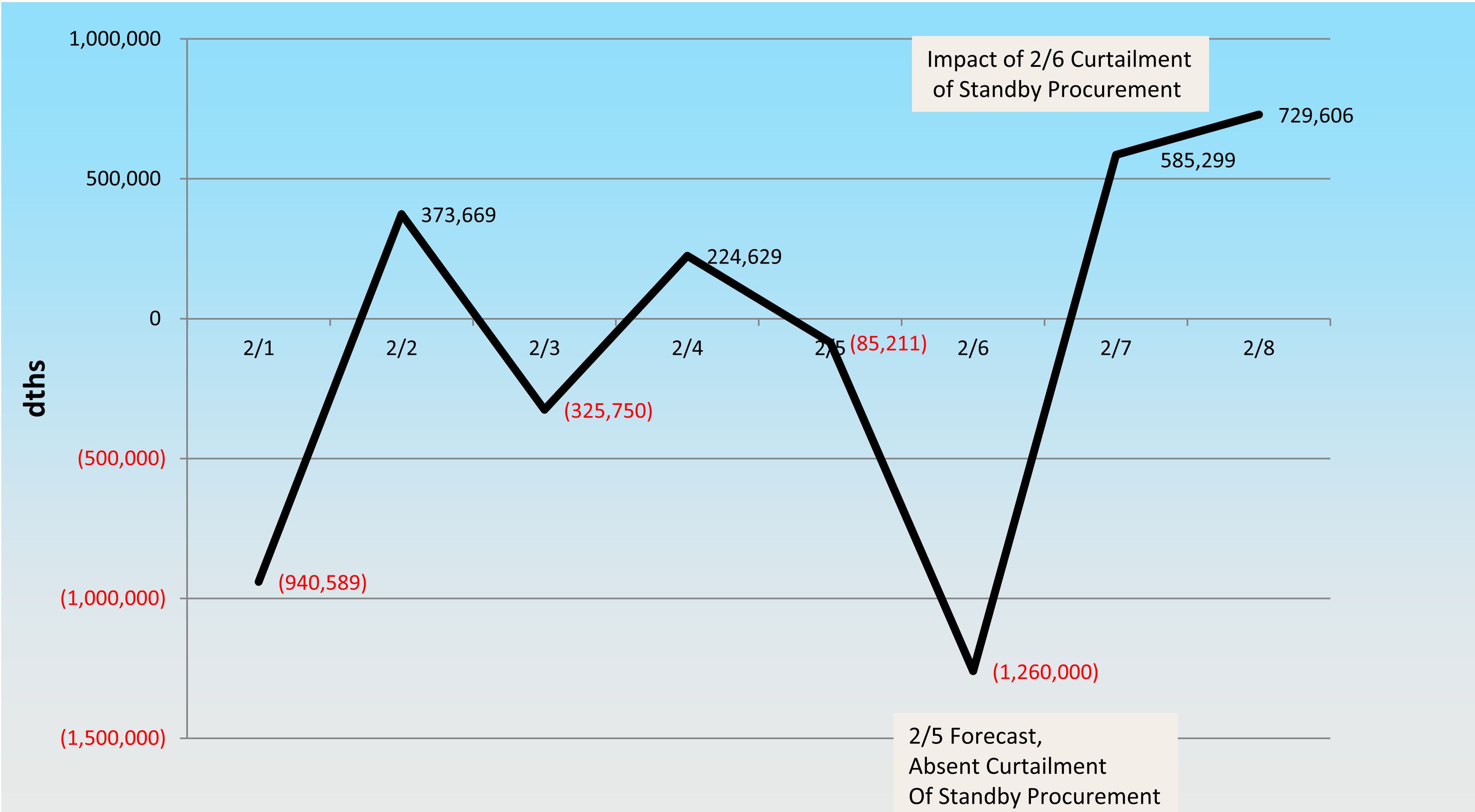
Need for a Low OFO

- 5-day, 50% balancing no longer conforms to market reality
- Despite winter balancing, curtailment of standby procurement was necessary on Dec. 6-11, 2013 and Feb 6-10, 2014
- Feb 6th, 2014 emergency curtailment of electric generators was necessary, and CAISO issued a FlexAlert
- Marketers, suppliers, customers diverted flowing supply to higher-value markets that had abnormally cold weather

Proposed Solution

- Replace winter balancing rules (circa 1997) with low OFO procedures similar to those on PG&E system.
  - Low OFOs appeared to adequately deal with supply diversions on PG&E system during last winter period.

February Storage Withdrawal Used for Balancing

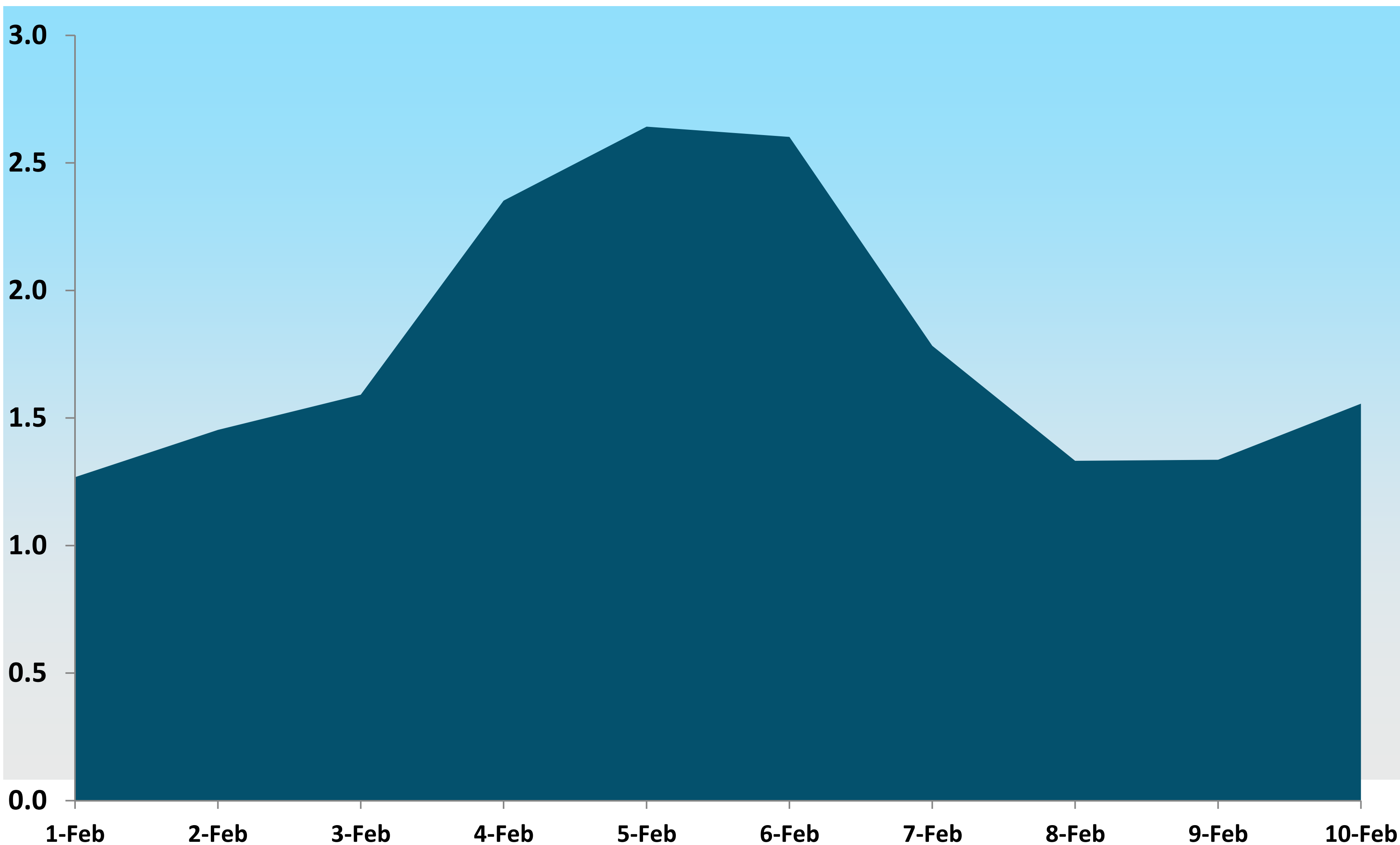


Source: Envoy Daily Operations

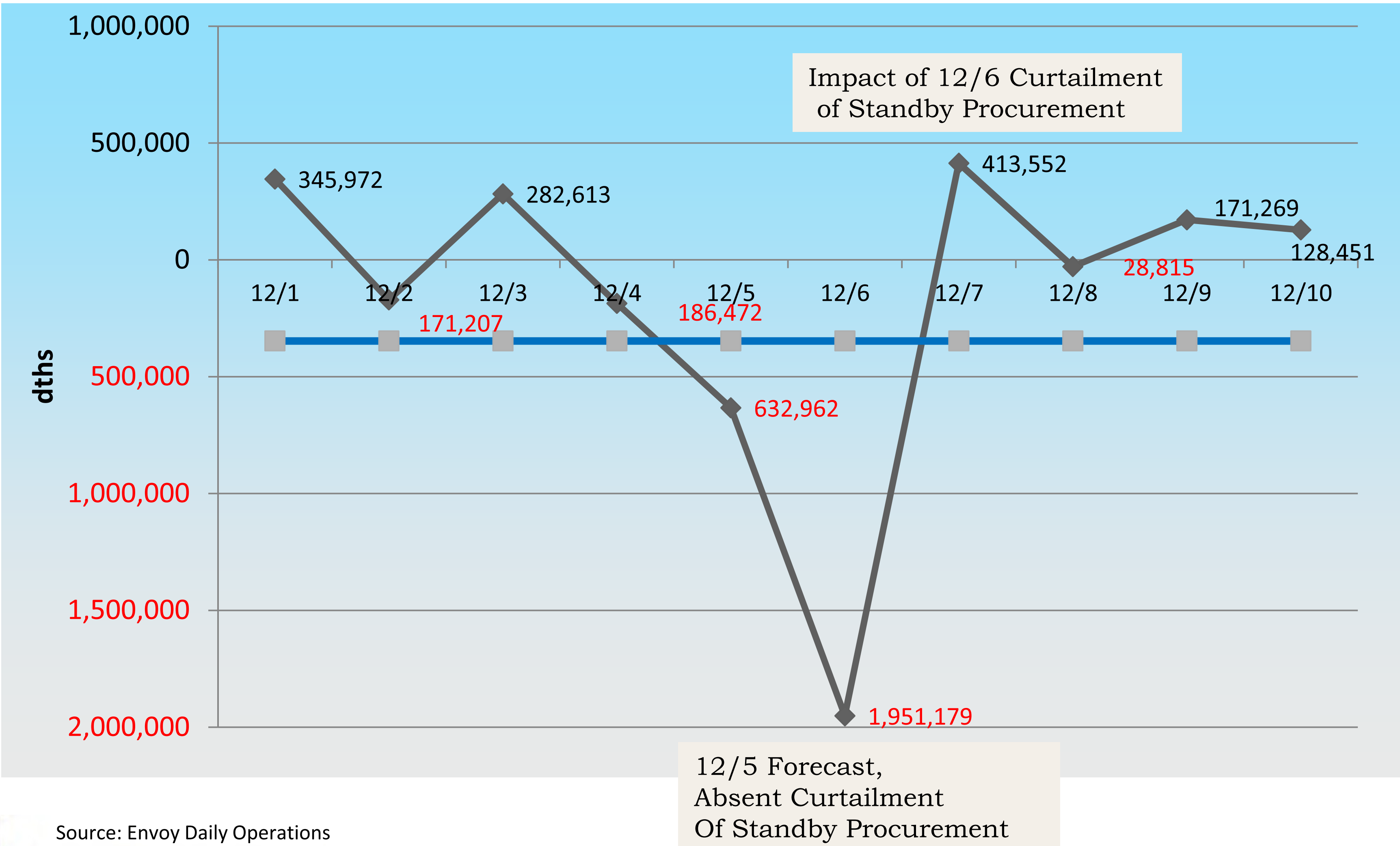
Southern California Gas Company A Sempra Energy utility®

Glad to be of service.®

Over-reliance of Storage Withdrawal – February 2014

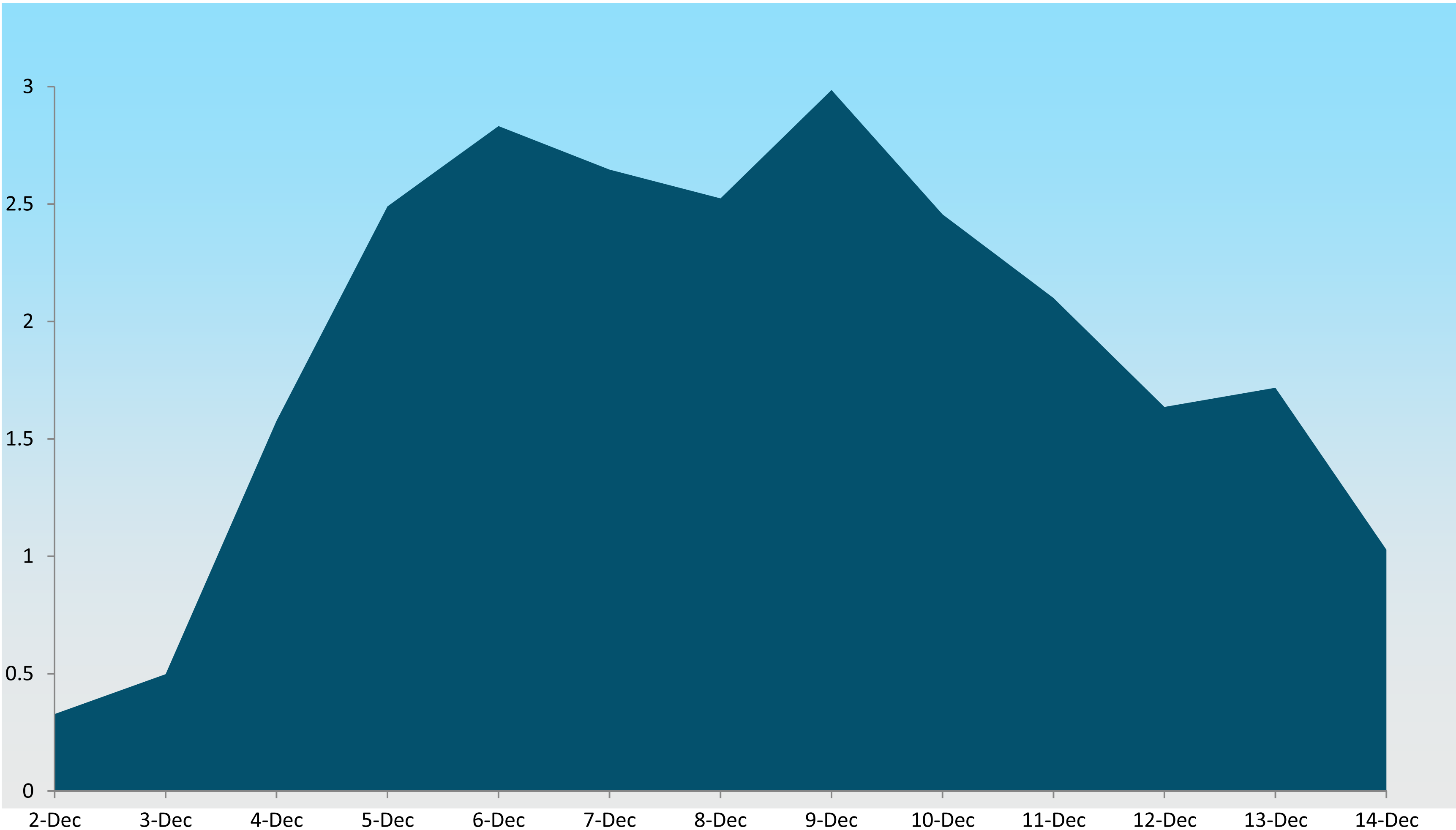


December Storage Withdrawal Used for Balancing



Source: Envoy Daily Operations

Over-reliance on Storage Withdrawal Dec. 2013



Southern California Gas Company A Sempra Energy utility®

Glad to be of service.®

PG&E Low OFO Approach

- PG&E has assets (primarily linepack) allocated to the balancing function and calls low OFOs when those assets are forecast to be depleted the next day
  - Applies throughout the year
  - PG&E chooses stage with noncompliance charges high enough to ensure compliance
- SoCalGas can adopt PG&E's approach by using the storage assets allocated to the balancing function as the trigger calculation
- SoCalGas can use PG&E's Stage tolerances and noncompliance penalty structure

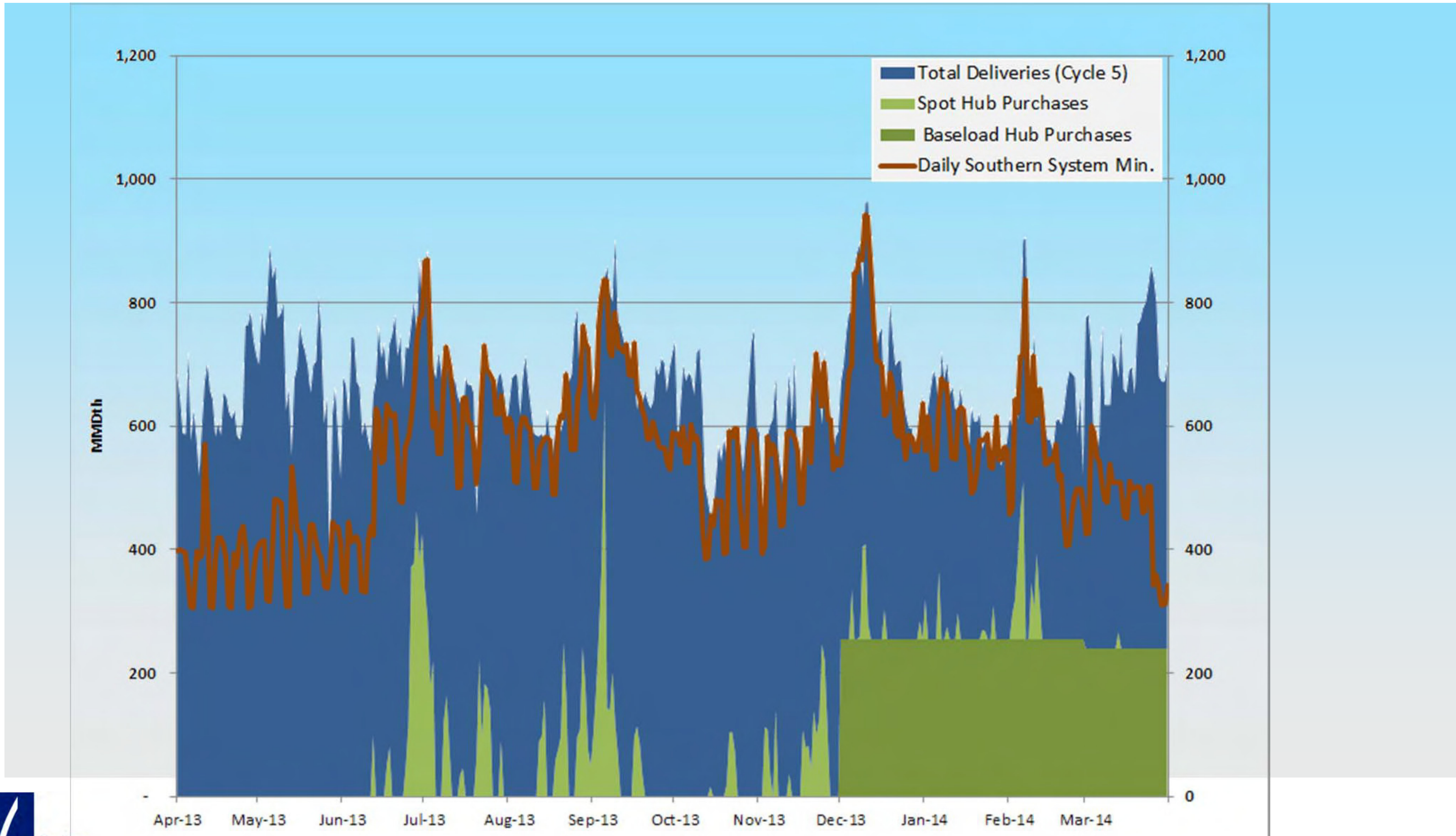
PG&E Low OFOs
2012-March 31, 2014

Stage	Tolerance	Average	Charge	# Events
1	Up to -25%	-6%	$0.25/Dth	22
2	Up to -20%	-7%	$1/Dth	6
3	Up to -15%	-5%	$5/Dth	4
4	Up to -5%	-5%	$25/Dth	4
5	Up to -5%	n/a	$25/Dth +city gate	0
EFO	Zero	n/a	$50/Dth + city gate	0

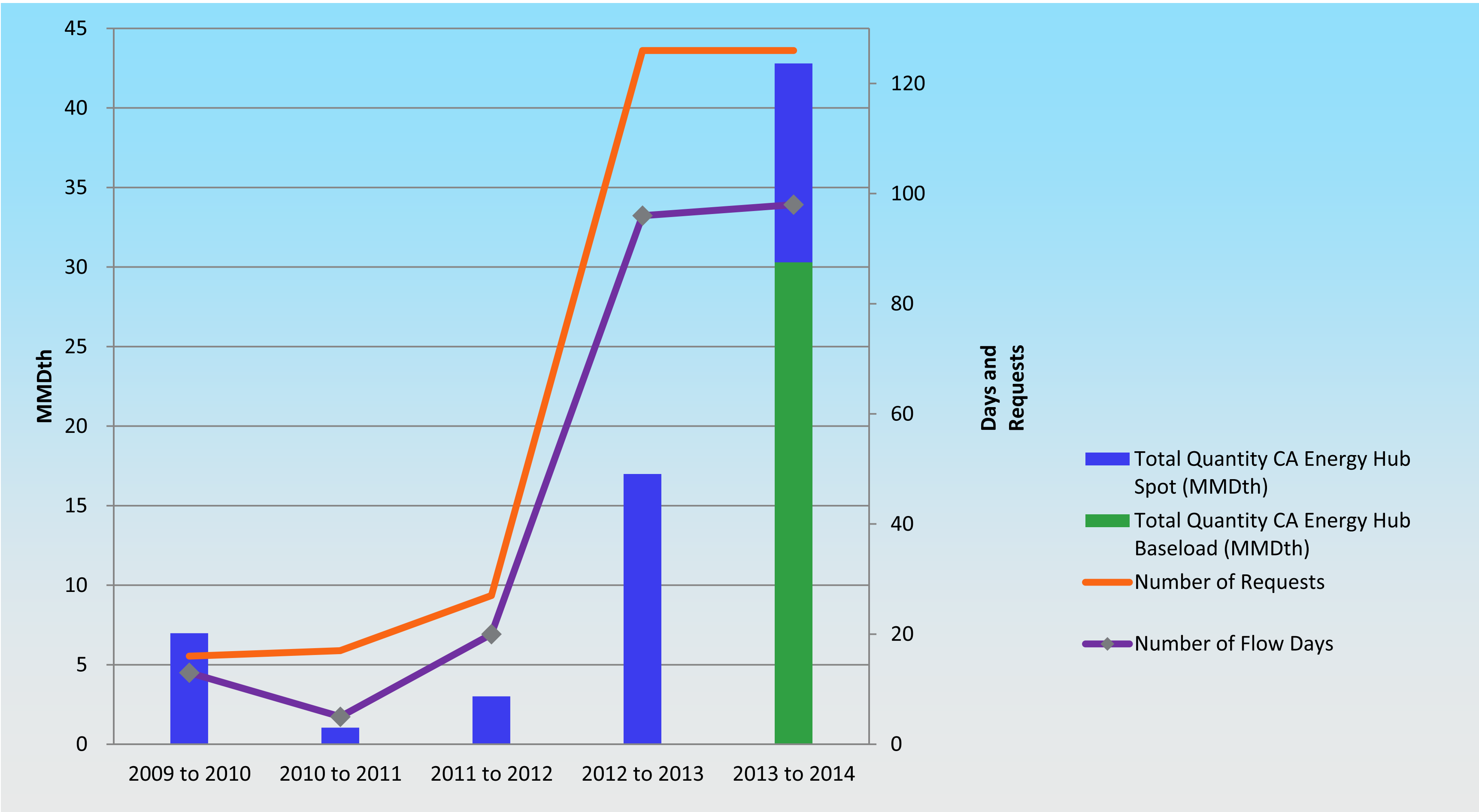
Proposed SoCalGas Low OFO Trigger

- SoCalGas calls low OFO when it forecasts more than 340 MMcfd (storage withdrawal allocated to balancing function) will be used for balancing the next day
- If (Forecasted Sendout – Forecasted Receipts – Forecasted Withdrawal from Storage Accounts) > 340 MMcfd of withdrawal from balancing, then low OFO
- Equal to “Daily Operations” screen line labelled “Storage Injection for Customer Balancing (Withdrawal)” in Envoy
- SoCalGas will strive to call low OFOs before 8 pm the day before flow

April 2013 - March 2014
Southern System Deliveries



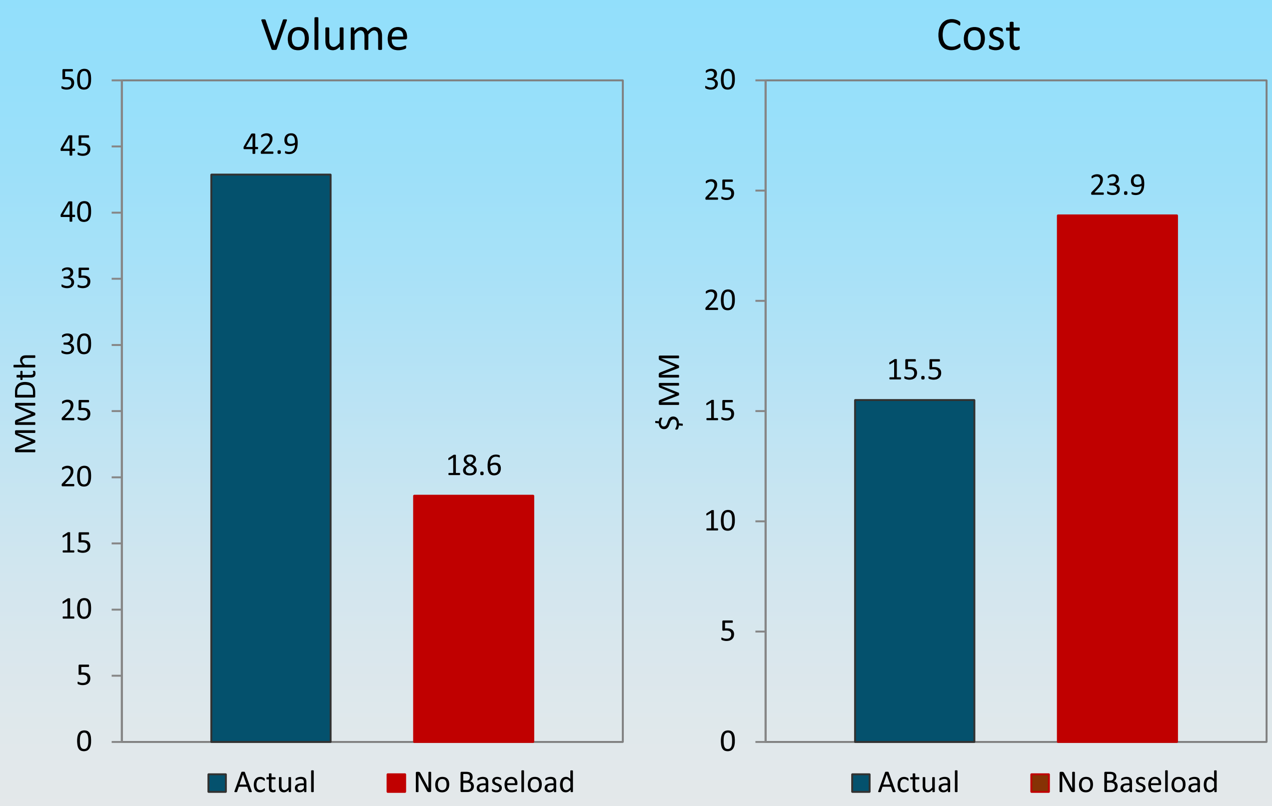
Southern System Historical Data



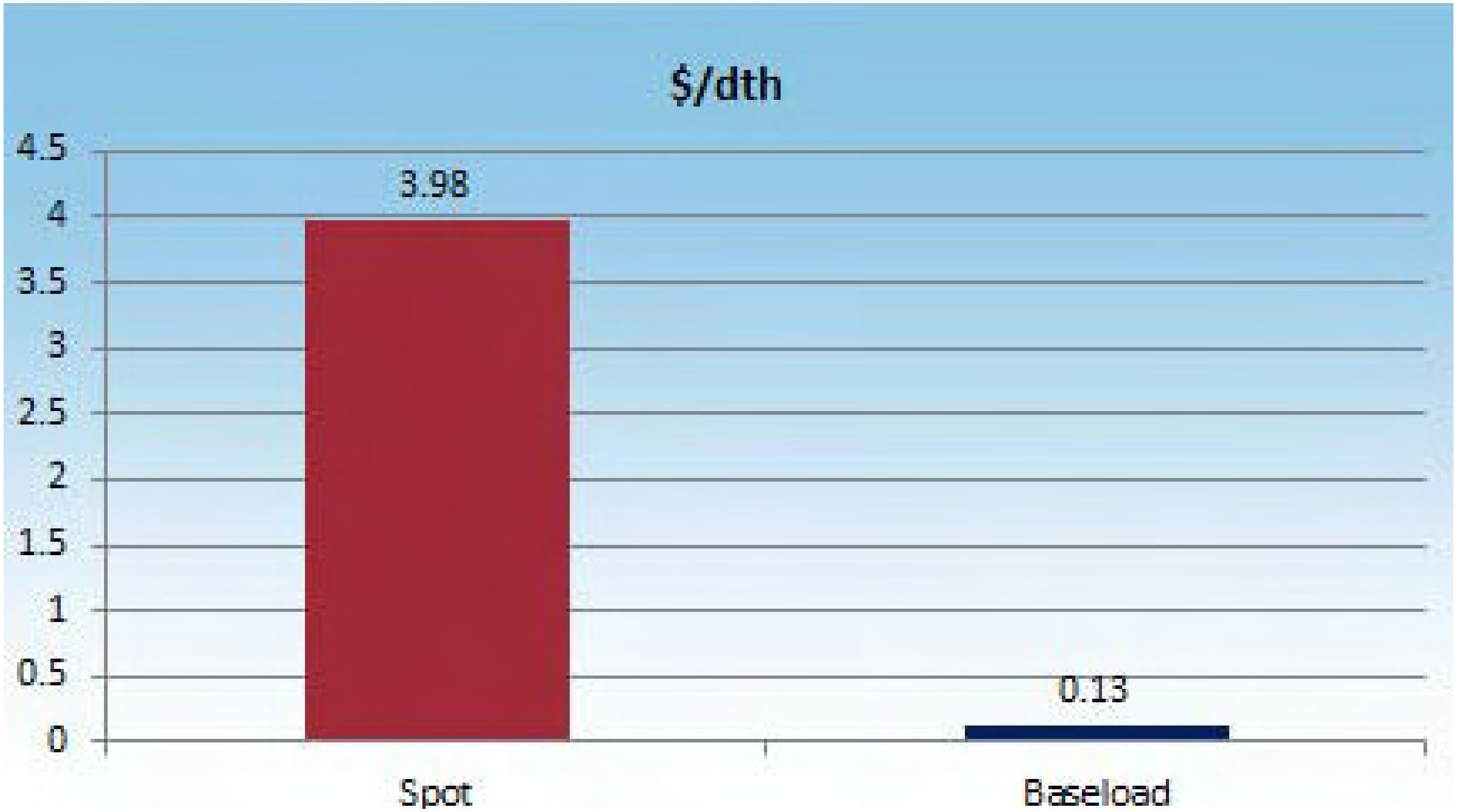
Southern System Reliability (SSR) Purchases and Interruptible BTS Discounts

	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014
Purchases (Dth)	6,983,793	1,044,677	3,014,544	16,988,817	42,878,668
SRMA Cost ($MM)	2.2	3.8	1.1	6.3	15.5
Net Cost ($/Dth)	0.31	3.63	0.36	0.37	0.36
BTS Discounts ($MM)	0	0	5.5	8.6	7.9
Total $MM	2.2	3.8	6.6	14.9	23.4

Baseload increased volumes but decreased cost by over $8MM



2013/2014 Winter Spot vs. Baseload Net Costs



High Operational Flow Order (High OFO)

- A High OFO is declared when SoCalGas determines that expected receipts will exceed total forecasted system capacity (including storage injection capacity and latest off-system scheduled quantities) for a pending flow day
- SoCalGas uses the on-system scheduled quantities from the latest scheduling cycle to determine expected system receipts for the High OFO calculation

Scheduled Quantities Used for High OFO

Cycle	Scheduled Quantity Used for OFO Calculation
Timely	*Prior* Day, Evening Cycle
Evening	Current Day, Timely Cycle
Intraday 1	Current Day, Evening Cycle
Intraday 2	Current Day, Intraday 1 Cycle

On High OFO days, SoCalGas will only confirm nominations up to the total system capacity for Intraday 1 (Cycle 3) and Intraday 2 (Cycle 4)

SoCalGas will not declare a High OFO on Intraday 2 (Cycle 4), but will limit the confirmations to the total system capacity as it does on all other days

High OFO Review

- 29 High OFO events during Review Period
- Reduction of 40% compared to previous reporting period of 48
- Almost all high OFOs occurred during shoulder months

High OFO Comparison

2013 Forum Report

- Cycle 1 29
- Cycle 2 6
- Cycle 3 13

Total 48

2014 Forum Report

- Cycle 1 18
- Cycle 2 5
- Cycle 3 6

Total 29

Potential Tool to Address Minimum Flow Requirements

No new tools proposed

Long Term System Improvement

North–South Project Revenue Requirement Application

(A.13-12-013)

- Filed on December 20, 2013
- Prehearing Conference held on March 13
- Commissioner Florio Scoping Memo issued 5-5-14

Gas-Electric Coordination

Daily Gas Control – CAISO Communication

- Done to ensure that CAISO is advised on the availability of system capacity to serve electric generation requirements
- The objective is to minimize outages and curtailments on both the electric grid and the SoCalGas/SDG&E gas systems

Gas-Electric Coordination (cont.)

Gas Day/Scheduling Cycle Modifications

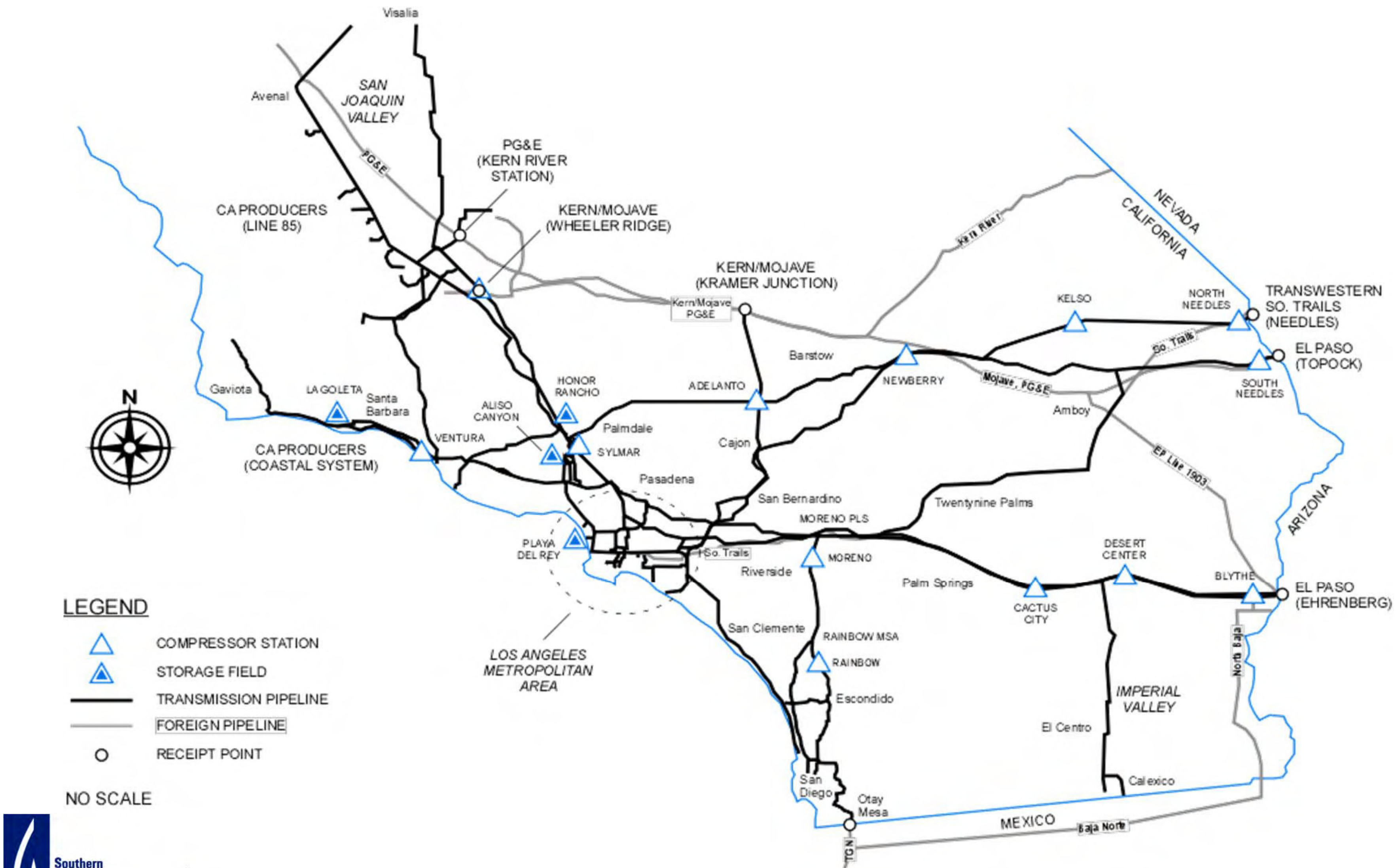
- The FERC is ready to take action to address Gas-Electric Coordination
- A proposed rule orders the interstate pipelines and ISO/RTOs to either accept exemplary changes to the Gas Day and Scheduling cycles or to make a consensus proposal by late June 2014
- Discussions are underway at NAESB to develop a consensus proposal

Post-Forum Report/Next Steps

- The post-Forum Report will summarize the matters discussed here and will identify action items, tariff changes and procedural modifications that we agree are necessary
  - Will include descriptions of proposals presented by meeting participants
  - Any proposals made that are rejected by SoCalGas will be included in the post-Forum Report
  - A draft post-Forum Report will be issued to the Forum participants for review by May 30 with a revised draft to be issued by June 6
  - If required, Customer Forum meeting participants will be invited to a conference call regarding the revised draft the week of June 16, to seek resolution of any differences
- Post-Forum Report will be filed by July 7, 2014

Appendix

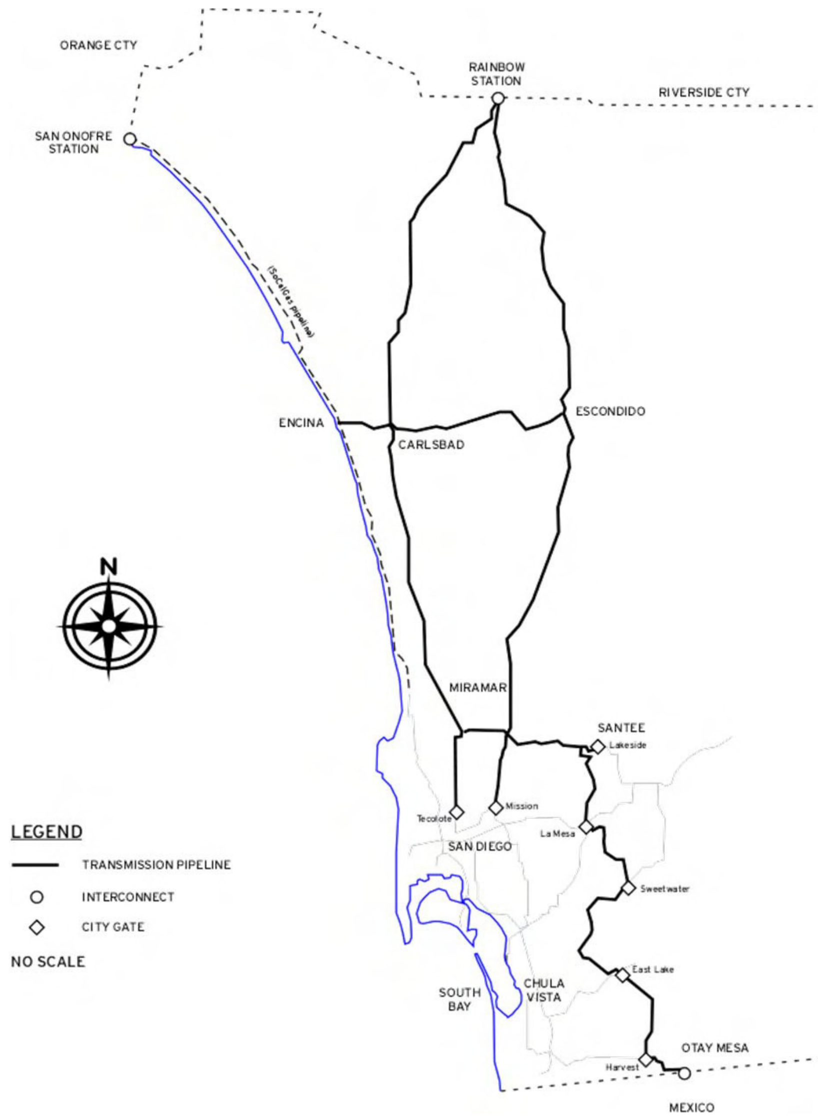
SoCalGas



Southern California Gas Company A Sempra Energy utility®

Glad to be of service.®

SDG&E



ORANGE CTY
RAINBOW STATION
RIVERSIDE CTY
SAN ONOFRE STATION
ENCINA
CARLSBAD
ESCONDIDO
N
MIRAMAR
SANTEE
Lakeside
Tecolote
Mission
SAN DIEGO
La Mesa
Sweetwater
East Lake
SOUTH BAY
CHULA VISTA
OTAY MESA
Harvest
MEXICO
LEGEND
TRANSMISSION PIPELINE
INTERCONNECT
CITY GATE
NO SCALE

Attachment B

SoCalGas ENVOY®

Search :

Log In

Home | Informational Postings ▾ | CA Energy Hub ▾ | Regulatory Releases ▾ | Envoy Forms | Register | Help ▾

Informational Postings

- Notices
- Receipt Point Capacity
- Storage Capacity
- Imbalance Trading
- Operations
  - Daily Operations
  - Hourly Operations
  - Capacity Utilization
  - OFO Calculation
  - Maintenance Schedules
- Wobbe Index

Search

Estimate Date: 12/05/2013

Daily Operations

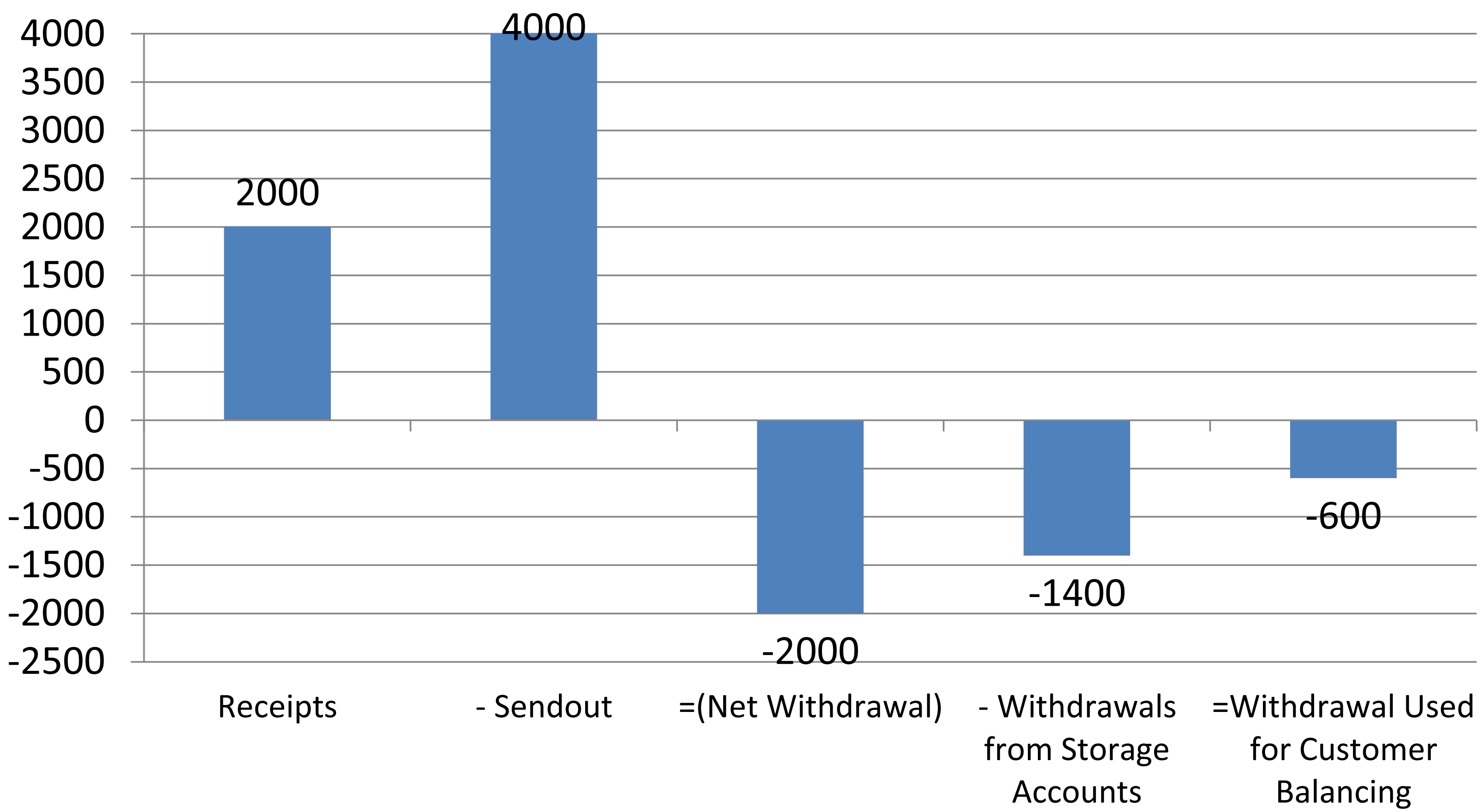
Archive | Derivation of Net System Capacity | Disclaimer

Last updated:

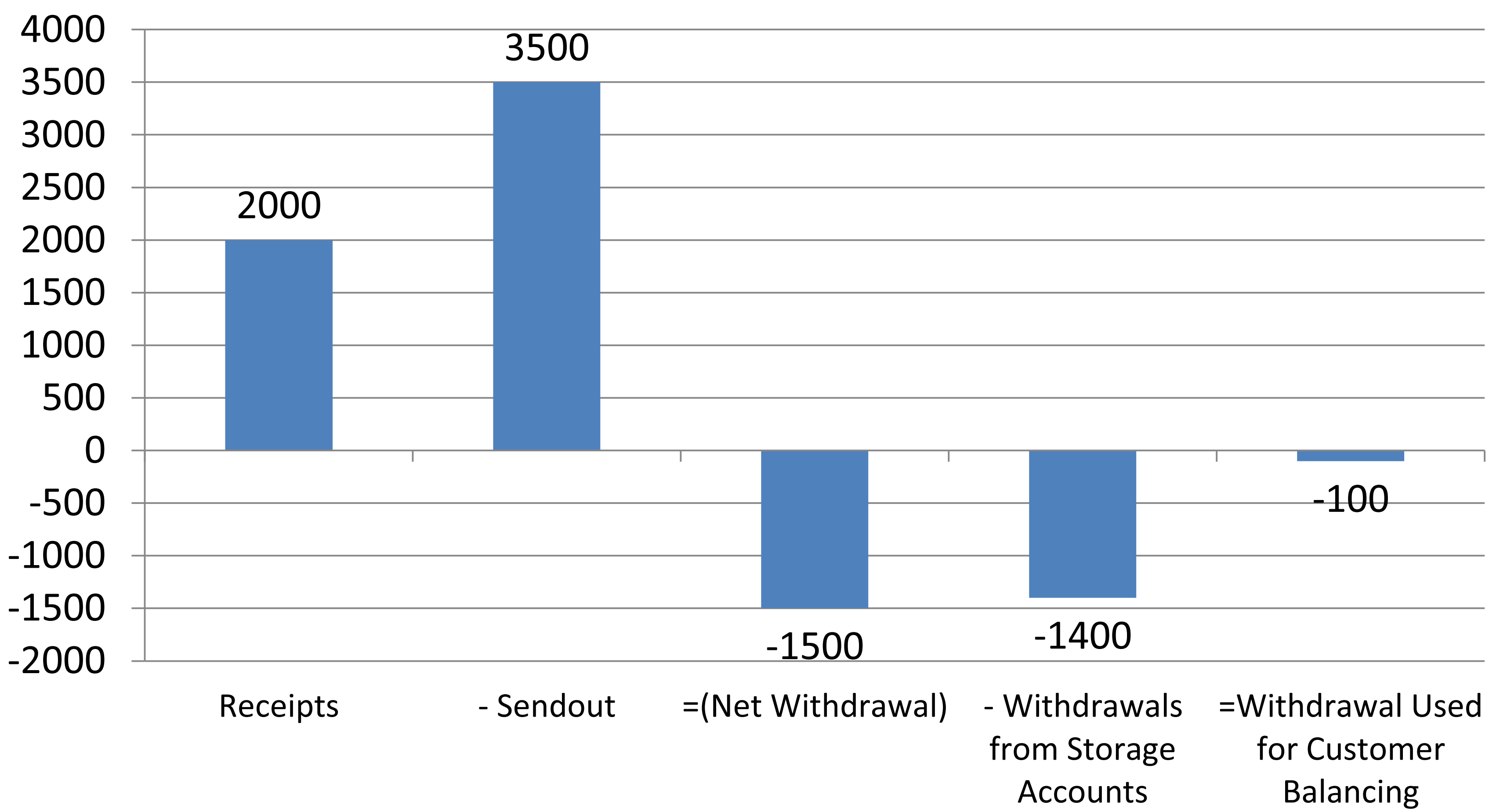
	Actual 12/04/2013	Estimate 12/05/2013	Forecast 12/06/2013	Forecast 12/07/2013	Forecast 12/08/2013
Receipts					
CP - Line 85	50,000	131,141	74,290	74,290	74,290
CP - North Coastal	38,000	44,407	44,708	44,708	44,708
CP - Others	21,000	27,622	28,665	28,665	28,665
El Paso - Ehrenberg	767,000	776,560	816,281	816,281	816,281
El Paso - Topock	60,000	7,874	36,791	36,791	36,791
Elk Hills - Wheeler Ridge	0	0	0	0	0
Kern River/Mojave - Kramer Junction	241,000	128,042	69,051	69,051	69,051
Kern River/Mojave - Wheeler Ridge	386,000	232,544	157,712	157,712	157,712
North Baja - Blythe	58,000	0	15,000	15,000	15,000
PG & E - Wheeler Ridge	65,000	70,557	72,067	72,067	72,067
Southern Trails - North Needles	38,000	21,200	27,900	27,900	27,900
TGN - Otay Mesa	0	0	0	0	0
Transwestern - North Needles	558,000	397,093	261,642	261,642	261,642
Transwestern - Topock	115,000	95,410	30,000	30,000	30,000
Total Receipts	2,398,000	1,932,450	1,634,107	1,634,107	1,634,107
Deliveries					
System Sendout	3,986,000	4,335,000	4,335,000	3,672,000	3,647,000
Total Deliveries	3,986,000	4,335,000	4,335,000	3,672,000	3,647,000
Net Injections(Withdrawals)	(1,577,000)	(2,402,550)	(2,700,893)	(2,037,893)	(2,012,893)
Injection Capacity		362,000	362,000	362,000	362,000
Withdrawal Capacity		3,090,000	3,090,000	3,090,000	3,090,000
Ending Storage Balance (MCF)	121,588,000	119,185,450	116,484,557	114,446,664	112,433,771
Balancing					
Total Daily Customer Imbalance	(186,472)	(545,512)	(1,951,179)	(1,288,179)	(1,263,179)
Cumulative Customer Imbalance	(505,223)				
Storage Injection for Customer Balancing(Withdrawal)	(186,472)	(545,512)	(1,951,179)	(1,288,179)	(1,263,179)
Transmission Fuel Use	6,952	5,602	4,737	4,737	4,737

Attachment C

Example of Daily Posting Indicating Low OFO Potential



Example of Daily Posting Indicating No Low OFO



Attachment D

(Mar-13 to Apr-14)

Gas Flow	Actual	Low OFO
		(515,000)
4/1/2013	256056	
4/2/2013	234907	
4/3/2013	-61887	
4/4/2013	148269	
4/5/2013	240898	
4/6/2013	-3248	
4/7/2013	58327	
4/8/2013	-291017	
4/9/2013	-76507	
4/10/2013	-82289	
4/11/2013	-182766	
4/12/2013	270490	
4/13/2013	242820	
4/14/2013	-6133	
4/15/2013	-254002	
4/16/2013	-216763	
4/17/2013	-326873	
4/18/2013	-115171	
4/19/2013	-15203	
4/20/2013	256713	
4/21/2013	180713	
4/22/2013	-180992	
4/23/2013	-236231	
4/24/2013	-394552	
4/25/2013	-189373	
4/26/2013	36908	
4/27/2013	208611	
4/28/2013	202854	
4/29/2013	-133381	
4/30/2013	173412	
5/1/2013	-222247	
5/2/2013	-58038	
5/3/2013	289978	
5/4/2013	547980	
5/5/2013	501151	
5/6/2013	259862	
5/7/2013	289771	
5/8/2013	350265	
5/9/2013	144747	
5/10/2013	358651	
5/11/2013	-241262	
5/12/2013	352397	
5/13/2013	-262071	
5/14/2013	168563	
5/15/2013	484526	
5/16/2013	78244	

5/17/2013	-201953
5/18/2013	-56770
5/19/2013	413811
5/20/2013	39164
5/21/2013	310249
5/22/2013	84837
5/23/2013	51439
5/24/2013	180770
5/25/2013	-290005
5/26/2013	-478593
5/27/2013	-803
5/28/2013	-642669
5/29/2013	-632252
5/30/2013	-781082
5/31/2013	-649660
6/1/2013	221706
6/2/2013	438354
6/3/2013	251047
6/4/2013	588135
6/5/2013	537622
6/6/2013	310813
6/7/2013	522840
6/8/2013	-199676
6/9/2013	-266048
6/10/2013	310584
6/11/2013	522166
6/12/2013	-415179
6/13/2013	348610
6/14/2013	-95779
6/15/2013	68099
6/16/2013	-229187
6/17/2013	60525
6/18/2013	-68563
6/19/2013	189323
6/20/2013	344320
6/21/2013	281975
6/22/2013	253513
6/23/2013	-51836
6/24/2013	124087
6/25/2013	151151
6/26/2013	-113858
6/27/2013	-218710
6/28/2013	-466178
6/29/2013	-603683
6/30/2013	-571677
7/1/2013	-813217
7/2/2013	-275600

7/3/2013	399852
7/4/2013	315078
7/5/2013	456522
7/6/2013	562604
7/7/2013	409460
7/8/2013	-270330
7/9/2013	-494819
7/10/2013	26605
7/11/2013	23336
7/12/2013	317070
7/13/2013	317381
7/14/2013	324381
7/15/2013	-122846
7/16/2013	-31642
7/17/2013	-120706
7/18/2013	-192851
7/19/2013	36960
7/20/2013	-67774
7/21/2013	-194452
7/22/2013	-434943
7/23/2013	-63770
7/24/2013	-337499
7/25/2013	-9223
7/26/2013	83399
7/27/2013	421721
7/28/2013	468811
7/29/2013	495477
7/30/2013	164266
7/31/2013	185889
8/1/2013	315166
8/2/2013	292510
8/3/2013	340017
8/4/2013	406592
8/5/2013	124623
8/6/2013	154296
8/7/2013	369763
8/8/2013	51027
8/9/2013	60260
8/10/2013	324179
8/11/2013	272980
8/12/2013	-141390
8/13/2013	-30007
8/14/2013	37997
8/15/2013	-266771
8/16/2013	-83823
8/17/2013	143541
8/18/2013	-135951

8/19/2013	-488800
8/20/2013	-238593
8/21/2013	-406372
8/22/2013	-469248
8/23/2013	27285
8/24/2013	304561
8/25/2013	115369
8/26/2013	-232311
8/27/2013	-497954
8/28/2013	-699905
8/29/2013	-655266
8/30/2013	-736898
8/31/2013	-134583
9/1/2013	43213
9/2/2013	-145546
9/3/2013	-783421
9/4/2013	-856531
9/5/2013	-373186
9/6/2013	-81383
9/7/2013	52286
9/8/2013	237715
9/9/2013	29224
9/10/2013	525885
9/11/2013	-58693
9/12/2013	143762
9/13/2013	56239
9/14/2013	187846
9/15/2013	87553
9/16/2013	-106998
9/17/2013	-53296
9/18/2013	-140721
9/19/2013	-53428
9/20/2013	343432
9/21/2013	331379
9/22/2013	372511
9/23/2013	32604
9/24/2013	266222
9/25/2013	286368
9/26/2013	188329
9/27/2013	326152
9/28/2013	313995
9/29/2013	444010
9/30/2013	178477
10/1/2013	186142
10/2/2013	25950
10/3/2013	-11004
10/4/2013	227215

10/5/2013	465564
10/6/2013	457166
10/7/2013	-289942
10/8/2013	110441
10/9/2013	-89974
10/10/2013	-30100
10/11/2013	-482
10/12/2013	5494
10/13/2013	26290
10/14/2013	-501057
10/15/2013	-557360
10/16/2013	-647908
10/17/2013	-153705
10/18/2013	-81765
10/19/2013	-199802
10/20/2013	-181950
10/21/2013	-375914
10/22/2013	-403514
10/23/2013	-288503
10/24/2013	-13473
10/25/2013	-156309
10/26/2013	63557
10/27/2013	-275650
10/28/2013	-599458
10/29/2013	-186381
10/30/2013	-211328
10/31/2013	-190207
11/1/2013	129505
11/2/2013	-11765
11/3/2013	72557
11/4/2013	-182735
11/5/2013	-68758
11/6/2013	-138902
11/7/2013	255928
11/8/2013	99867
11/9/2013	17918
11/10/2013	-40470
11/11/2013	-183350
11/12/2013	94862
11/13/2013	343687
11/14/2013	97514
11/15/2013	221025
11/16/2013	245653
11/17/2013	-23822
11/18/2013	632196
11/19/2013	368876
11/20/2013	121444

11/21/2013	-385487
11/22/2013	-788588
11/23/2013	-397594
11/24/2013	-491420
11/25/2013	-987045
11/26/2013	803830
11/27/2013	496498
11/28/2013	266639
11/29/2013	-143897
11/30/2013	151770
12/1/2013	345942
12/2/2013	-171207
12/3/2013	282613
12/4/2013	-186472
12/5/2013	-632962
12/6/2013	-196811
12/7/2013	312325
12/8/2013	413552
12/9/2013	-28815
12/10/2013	171269
12/11/2013	128417
12/12/2013	518276
12/13/2013	134913
12/14/2013	322224
12/15/2013	854278
12/16/2013	406000
12/17/2013	-79005
12/18/2013	-584224
12/19/2013	530887
12/20/2013	172119
12/21/2013	43773
12/22/2013	-110502
12/23/2013	20498
12/24/2013	245454
12/25/2013	508019
12/26/2013	32501
12/27/2013	-32873
12/28/2013	345954
12/29/2013	115955
12/30/2013	-330657
12/31/2013	295098
1/1/2014	-98104
1/2/2014	-227168
1/3/2014	-118225
1/4/2014	-328952
1/5/2014	-527687
1/6/2014	-1046448

= Standby Procurement Days
Withdrawals by balancing
Customers tended to cease

1/7/2014	-1161748
1/8/2014	331631
1/9/2014	-180435
1/10/2014	172304
1/11/2014	174824
1/12/2014	999324
1/13/2014	-84676
1/14/2014	-69734
1/15/2014	-142735
1/16/2014	-209830
1/17/2014	-271517
1/18/2014	213794
1/19/2014	69791
1/20/2014	-184211
1/21/2014	-303546
1/22/2014	-239439
1/23/2014	-607450
1/24/2014	844381
1/25/2014	170308
1/26/2014	673233
1/27/2014	74966
1/28/2014	245414
1/29/2014	-129817
1/30/2014	116473
1/31/2014	650810
2/1/2014	-940589
2/2/2014	373669
2/3/2014	-325750
2/4/2014	224629
2/5/2014	-85211
2/6/2014	385579
2/7/2014	585299
2/8/2014	729606
2/9/2014	438225
2/10/2014	280776
2/11/2014	-100830
2/12/2014	-121430
2/13/2014	-241972
2/14/2014	-102008
2/15/2014	-174830
2/16/2014	107872
2/17/2014	33664
2/18/2014	62265
2/19/2014	77975
2/20/2014	-272694
2/21/2014	-27335
2/22/2014	-158184

2/23/2014	-136516
2/24/2014	-232829
2/25/2014	148907
2/26/2014	206450
2/27/2014	306341
2/28/2014	199082
3/1/2014	159795
3/2/2014	103084
3/3/2014	52541
3/4/2014	-33039
3/5/2014	-174150
3/6/2014	174101
3/7/2014	271634
3/8/2014	25710
3/9/2014	319025
3/10/2014	235883
3/11/2014	131230
3/12/2014	-80312
3/13/2014	14139
3/14/2014	129028
3/15/2014	-132761
3/16/2014	230278
3/17/2014	210049
3/18/2014	76805
3/19/2014	95813
3/20/2014	-17142
3/21/2014	-227825
3/22/2014	162591
3/23/2014	-8658
3/24/2014	-235207
3/25/2014	146378
3/26/2014	80928
3/27/2014	26802
3/28/2014	-43241
3/29/2014	46139
3/30/2014	265046
3/31/2014	61809
Count	**24**

(Mar-13 to Apr-14)

Gas Flow date	Actual Storage Wdr for Cust Balancing	Low OFO
		(350,200)
4/1/2013	256056	
4/2/2013	234907	
4/3/2013	-61887	
4/4/2013	148269	
4/5/2013	240898	
4/6/2013	-3248	
4/7/2013	58327	
4/8/2013	-291017	
4/9/2013	-76507	
4/10/2013	-82289	
4/11/2013	-182766	
4/12/2013	270490	
4/13/2013	242820	
4/14/2013	-6133	
4/15/2013	-254002	
4/16/2013	-216763	
4/17/2013	-326873	
4/18/2013	-115171	
4/19/2013	-15203	
4/20/2013	256713	
4/21/2013	180713	
4/22/2013	-180992	
4/23/2013	-236231	
4/24/2013	-394552	
4/25/2013	-189373	
4/26/2013	36908	
4/27/2013	208611	
4/28/2013	202854	
4/29/2013	-133381	
4/30/2013	173412	
5/1/2013	-222247	
5/2/2013	-58038	
5/3/2013	289978	
5/4/2013	547980	
5/5/2013	501151	
5/6/2013	259862	
5/7/2013	289771	
5/8/2013	350265	
5/9/2013	144747	
5/10/2013	358651	
5/11/2013	-241262	
5/12/2013	352397	
5/13/2013	-262071	

5/14/2013	168563
5/15/2013	484526
5/16/2013	78244
5/17/2013	-201953
5/18/2013	-56770
5/19/2013	413811
5/20/2013	39164
5/21/2013	310249
5/22/2013	84837
5/23/2013	51439
5/24/2013	180770
5/25/2013	-290005
5/26/2013	-478593
5/27/2013	-803
5/28/2013	-642669
5/29/2013	-632252
5/30/2013	-781082
5/31/2013	-649660
6/1/2013	221706
6/2/2013	438354
6/3/2013	251047
6/4/2013	588135
6/5/2013	537622
6/6/2013	310813
6/7/2013	522840
6/8/2013	-199676
6/9/2013	-266048
6/10/2013	310584
6/11/2013	522166
6/12/2013	-415179
6/13/2013	348610
6/14/2013	-95779
6/15/2013	68099
6/16/2013	-229187
6/17/2013	60525
6/18/2013	-68563
6/19/2013	189323
6/20/2013	344320
6/21/2013	281975
6/22/2013	253513
6/23/2013	-51836
6/24/2013	124087
6/25/2013	151151
6/26/2013	-113858
6/27/2013	-218710
6/28/2013	-466178
6/29/2013	-603683

6/30/2013	-571677
7/1/2013	-813217
7/2/2013	-275600
7/3/2013	399852
7/4/2013	315078
7/5/2013	456522
7/6/2013	562604
7/7/2013	409460
7/8/2013	-270330
7/9/2013	-494819
7/10/2013	26605
7/11/2013	23336
7/12/2013	317070
7/13/2013	317381
7/14/2013	324381
7/15/2013	-122846
7/16/2013	-31642
7/17/2013	-120706
7/18/2013	-192851
7/19/2013	36960
7/20/2013	-67774
7/21/2013	-194452
7/22/2013	-434943
7/23/2013	-63770
7/24/2013	-337499
7/25/2013	-9223
7/26/2013	83399
7/27/2013	421721
7/28/2013	468811
7/29/2013	495477
7/30/2013	164266
7/31/2013	185889
8/1/2013	315166
8/2/2013	292510
8/3/2013	340017
8/4/2013	406592
8/5/2013	124623
8/6/2013	154296
8/7/2013	369763
8/8/2013	51027
8/9/2013	60260
8/10/2013	324179
8/11/2013	272980
8/12/2013	-141390
8/13/2013	-30007
8/14/2013	37997
8/15/2013	-266771

8/16/2013	-83823
8/17/2013	143541
8/18/2013	-135951
8/19/2013	-488800
8/20/2013	-238593
8/21/2013	-406372
8/22/2013	-469248
8/23/2013	27285
8/24/2013	304561
8/25/2013	115369
8/26/2013	-232311
8/27/2013	-497954
8/28/2013	-699905
8/29/2013	-655266
8/30/2013	-736898
8/31/2013	-134583
9/1/2013	43213
9/2/2013	-145546
9/3/2013	-783421
9/4/2013	-856531
9/5/2013	-373186
9/6/2013	-81383
9/7/2013	52286
9/8/2013	237715
9/9/2013	29224
9/10/2013	525885
9/11/2013	-58693
9/12/2013	143762
9/13/2013	56239
9/14/2013	187846
9/15/2013	87553
9/16/2013	-106998
9/17/2013	-53296
9/18/2013	-140721
9/19/2013	-53428
9/20/2013	343432
9/21/2013	331379
9/22/2013	372511
9/23/2013	32604
9/24/2013	266222
9/25/2013	286368
9/26/2013	188329
9/27/2013	326152
9/28/2013	313995
9/29/2013	444010
9/30/2013	178477
10/1/2013	186142

10/2/2013	25950
10/3/2013	-11004
10/4/2013	227215
10/5/2013	465564
10/6/2013	457166
10/7/2013	-289942
10/8/2013	110441
10/9/2013	-89974
10/10/2013	-30100
10/11/2013	-482
10/12/2013	5494
10/13/2013	26290
10/14/2013	-501057
10/15/2013	-557360
10/16/2013	-647908
10/17/2013	-153705
10/18/2013	-81765
10/19/2013	-199802
10/20/2013	-181950
10/21/2013	-375914
10/22/2013	-403514
10/23/2013	-288503
10/24/2013	-13473
10/25/2013	-156309
10/26/2013	63557
10/27/2013	-275650
10/28/2013	-599458
10/29/2013	-186381
10/30/2013	-211328
10/31/2013	-190207
11/1/2013	129505
11/2/2013	-11765
11/3/2013	72557
11/4/2013	-182735
11/5/2013	-68758
11/6/2013	-138902
11/7/2013	255928
11/8/2013	99867
11/9/2013	17918
11/10/2013	-40470
11/11/2013	-183350
11/12/2013	94862
11/13/2013	343687
11/14/2013	97514
11/15/2013	221025
11/16/2013	245653
11/17/2013	-23822

11/18/2013	632196
11/19/2013	368876
11/20/2013	121444
11/21/2013	-385487
11/22/2013	-788588
11/23/2013	-397594
11/24/2013	-491420
11/25/2013	-987045
11/26/2013	803830
11/27/2013	496498
11/28/2013	266639
11/29/2013	-143897
11/30/2013	151770
12/1/2013	345942
12/2/2013	-171207
12/3/2013	282613
12/4/2013	-186472
12/5/2013	-632962
12/6/2013	-196811
12/7/2013	312325
12/8/2013	413552
12/9/2013	-28815
12/10/2013	171269
12/11/2013	128417
12/12/2013	518276
12/13/2013	134913
12/14/2013	322224
12/15/2013	854278
12/16/2013	406000
12/17/2013	-79005
12/18/2013	-584224
12/19/2013	530887
12/20/2013	172119
12/21/2013	43773
12/22/2013	-110502
12/23/2013	20498
12/24/2013	245454
12/25/2013	508019
12/26/2013	32501
12/27/2013	-32873
12/28/2013	345954
12/29/2013	115955
12/30/2013	-330657
12/31/2013	295098
1/1/2014	-98104
1/2/2014	-227168
1/3/2014	-118225

= Standby Procurement Days
Withdrawals by balancing
Customers tended to cease

1/4/2014	-328952
1/5/2014	-527687
1/6/2014	-1046448
1/7/2014	-1161748
1/8/2014	331631
1/9/2014	-180435
1/10/2014	172304
1/11/2014	174824
1/12/2014	999324
1/13/2014	-84676
1/14/2014	-69734
1/15/2014	-142735
1/16/2014	-209830
1/17/2014	-271517
1/18/2014	213794
1/19/2014	69791
1/20/2014	-184211
1/21/2014	-303546
1/22/2014	-239439
1/23/2014	-607450
1/24/2014	844381
1/25/2014	170308
1/26/2014	673233
1/27/2014	74966
1/28/2014	245414
1/29/2014	-129817
1/30/2014	116473
1/31/2014	650810
2/1/2014	-940589
2/2/2014	373669
2/3/2014	-325750
2/4/2014	224629
2/5/2014	-85211
2/6/2014	385579
2/7/2014	585299
2/8/2014	729606
2/9/2014	438225
2/10/2014	280776
2/11/2014	-100830
2/12/2014	-121430
2/13/2014	-241972
2/14/2014	-102008
2/15/2014	-174830
2/16/2014	107872
2/17/2014	33664
2/18/2014	62265
2/19/2014	77975

2/20/2014	-272694
2/21/2014	-27335
2/22/2014	-158184
2/23/2014	-136516
2/24/2014	-232829
2/25/2014	148907
2/26/2014	206450
2/27/2014	306341
2/28/2014	199082
3/1/2014	159795
3/2/2014	103084
3/3/2014	52541
3/4/2014	-33039
3/5/2014	-174150
3/6/2014	174101
3/7/2014	271634
3/8/2014	25710
3/9/2014	319025
3/10/2014	235883
3/11/2014	131230
3/12/2014	-80312
3/13/2014	14139
3/14/2014	129028
3/15/2014	-132761
3/16/2014	230278
3/17/2014	210049
3/18/2014	76805
3/19/2014	95813
3/20/2014	-17142
3/21/2014	-227825
3/22/2014	162591
3/23/2014	-8658
3/24/2014	-235207
3/25/2014	146378
3/26/2014	80928
3/27/2014	26802
3/28/2014	-43241
3/29/2014	46139
3/30/2014	265046
3/31/2014	61809
Count	**41**

Attachment B

SoCalGas G-TBS

Schedule No. G-TBS Sheet 1

TRANSACTION BASED STORAGE SERVICE

APPLICABILITY

Applicable for unbundled firm or interruptible storage service, comprised of inventory, injection and withdrawal components, to any creditworthy party, including the Utility's Gas Procurement Department for any storage capacity that is additional to their Commission-allocated core storage rights. This schedule will be used for unbundled storage contracts executed from the effective date of this schedule. All eligible participants, including the Utility's Gas Procurement Department, are collectively referred to herein as "customers" unless otherwise specified.

Under this storage service rate schedule, the Utility shall provide unbundled storage services for a term of no more than three years (and no more than five years for wholesale core customer requirements) without CPUC approval. For terms more than three years, the Utility will seek CPUC approval. The storage service and associated charges shall be negotiated between the customer and the Utility, provided that the reservation charges do not exceed the applicable Component Rate Caps for this schedule.

All unsubscribed storage capacity will be available for customer subscription under this schedule. Customers may seek bundled or individual component services. The Utility may, however, impose limits pursuant to this schedule on the amount of unbundled storage services that a customer may acquire (e.g., the Utility may establish minimum or maximum levels of bundled services in conjunction with unbundled storage services). For example, the Utility may require customers to purchase a certain level of injection and withdrawal services in combination with inventory, or visa-versa.

The Utility may discount its storage services on a nondiscriminatory basis, and in compliance with all affiliate requirements. Nothing in this schedule is intended to affect the terms/conditions of customer contracts in effect prior to the effective date of this schedule.

TERRITORY

Applicable for gas stored by the Utility within its service territory.

RATES

Storage service rates under Schedule No. G-TBS consist of Reservation Charges, Volumetric Charges, and In-Kind Energy Charges. T

Firm Storage Service

The reservation charge, or price, for G-TBS storage service will be established between the customer and the Utility on a transactional basis dependent upon market conditions and the specific storage service to be provided to the customer. The price shall be set forth in the Contract and shall, unless otherwise specified in the Contract, be billed in equal monthly installments over the term of the Contract. The price under this schedule is applicable whether the service is used or not.

(Continued)

Schedule No. G-TBS Sheet 2

TRANSACTION BASED STORAGE SERVICE

D

(Continued)

RATES (Continued)

D

Component Rate Caps N

The Utility's per-unit reservation charges for a storage transaction may not exceed the following annual amounts for each component (i.e., inventory, injection, or withdrawal) of the package for packages with terms of one year or less. Customer preferences for annual packages in lieu of shorter-term packages will be honored to the extent annual capacity is available.

Inventory

Rate, per decatherm $1.63

Injection Capacity

Rate, per decatherm per day $60.00

Withdrawal Capacity

Rate, per decatherm per day $30.00

For example, inventory-only could be sold for $1.63/dth for any term up to one year. The maximum price for a package of 1,000,000 dth inventory with 5,000 dth/day of firm injection, and 10,000 dth/day of firm withdrawal will be $2,230,000 for any term of up to and including one year, $4,460,000 for any term more than one year but not more than two years, and $6,690,000 for any term more than two years but not more than three years. Similarly, the maximum price for a package of 1,000,000 dth inventory with 10,000 dth/day of firm injection, and 20,000 dth/day of firm withdrawal will be $2,830,000 for any term of up to and including one year, $5,660,000 for any term more than one year but not more than two years, and $8,490,000 for any term more than two years but not more than three years.

Interruptible Storage Service

Interruptible storage services for injection and withdrawal may be sold on a negotiated volumetric basis. The maximum rates for these services for each day of the service shall be $2.00/dth for withdrawal and $2.00/dth for injection. Interruptible services will be prioritized on the basis of price each day. Zero-priced, lowest-priority, interruptible injection and withdrawal service shall be included with all sales of inventory, whether that inventory is sold on a stand-alone or bundled basis. N

L

(Continued)

Schedule No. G-TBS Sheet 3
TRANSACTION BASED STORAGE SERVICE

(Continued)

RATES (Continued)

In-Kind Energy Charges

In-Kind Energy Charge, applied to all quantities delivered for injection during the year

Rate, percent reduction .... 2.40% I

The In-Kind Energy Charge shall be the same for all core and noncore injections and be adjusted as necessary on the basis of a three-year rolling average of actual fuel use.

SPECIAL CONDITIONS

General

1. The definitions of the principal terms used in this rate schedule and the Utility's other tariff schedules are contained in Rule No. 1.

2. Service under this schedule shall be curtailed in accordance with the provisions of Rule No. 23.

3. All terms and conditions of Rule No. 30 and Schedule No. G-IMB shall apply to the transportation of customer-owned gas in conjunction with the storage services provided under this schedule.

4. As a condition precedent to service under this schedule, an executed Master Services Contract (Form No. 6597) and an executed Master Services Contract, Schedule I, Transaction Based Storage Service (Form No. 6597-11) are required (referred to in this schedule collectively as the "Contract"). All contracts, rates and conditions are subject to revision and modification as a result of Commission order.

5. The contract term for service under this schedule shall be set forth in the customer's Contract.

6. Any quantity of storage gas that is in excess of the inventory rights remaining after: a) the customer's storage Contract term expires; or b) the customer trades away some or all of its inventory rights; or c) the customer's storage Contract is terminated, for whatever reason, prior to the completion of the term of such Contract shall be immediately purchased by the Utility at the applicable Buy-Back Rate stated in Schedule No. G-IMB. The Buy-Back purchase amount paid to the customer may be reduced by any outstanding amounts owed by the customer for any other services provided by the Utility.

(Continued)

(Continued)

SPECIAL CONDITIONS (Continued)

Secondary Market Rights

7. Customers served under this schedule may assign their contract storage rights in full to another customer upon written notice to Utility and approval by the Utility, and such approval shall not be unreasonably withheld by the Utility. Customers shall also have the same secondary market rights as established for all other storage customers, or as otherwise provided by Commission order. T

Storage Nominations

8. Storage customers must provide the Utility with their nominations for storage injections and/or withdrawals pursuant to Rule No. 30. T

9. G-TBS customers may designate an agent to act on their behalf for the purpose of making storage nominations for their service under this schedule. T

Storage Imbalance Trading

10. Except during any period of system curtailment, as described in Rule No. 23, G-TBS customers may use their available storage inventory capacity and quantities to (1) offset the customer's own transportation imbalances, or (2) trade with other customers for their transportation imbalances, under the imbalance trading provisions set forth in Schedule No. G-IMB. T

11. For storage injections and withdrawals performed through imbalance trading, the customer shall not be required to have storage injection or withdrawal rights but shall be assessed the In-Kind Energy Charges, set forth herein for such storage operations, at the time the imbalance trade is completed by the Utility. T D

D

(Continued)

Schedule No. G-TBS
TRANSACTION BASED STORAGE SERVICE

Sheet 5

(Continued)

SPECIAL CONDITIONS (Continued)

Storage Inventory Transfers

12. Storage customers may mutually request to transfer gas in inventory from one customer's storage account to another. Such requests must be made by both parties to the inventory transfer and are limited to the inventory quantity available for transfer and the available inventory capacity of the receiving customer at the time the transfer is completed by the Utility. All transfers may be accepted or rejected, in whole or in part, by the Utility and shall not be deemed accepted until such time as the Utility notifies both customers of the completion of the transfer. T

Storage Open Season

13. The Utility may also sell G-TBS storage using various forms of storage open seasons, including auctions and individual negotiations. T

Rules Concerning Posted Transactions

14. Given that the value of storage services are highly dynamic, and can change not only daily, but even hourly, the Utility is not required to offer posted prices or contract terms to any other customers. The Utility will meet and confer with any market participant regarding why it did not offer them the same prices and contract terms as other posted transactions. If, after such a meet and confer session, any market participant is not satisfied with the Utility's explanation, they may petition the CPUC, pursuant to Section I of Rule No. 4, to require the Utility to offer them the same prices and contract terms as other posted transactions, and the Utility may oppose such petition. T

Firm Inventory

15. Negotiated amounts of ~~Z~~zero-priced, lowest-priority, interruptible injection and withdrawal service may ~~shall~~ be included with ~~all~~ sales of inventory~~, whether that inventory is sold on a stand-alone or package basis~~. T

Allocations for Wholesale Customers

T

16. The Utility will allocate unbundled storage capacities to the City of Long Beach and Southwest Gas in a manner consistent with D.08-12-020 and any applicable CPUC decisions relating to storage allocations to these customers.

SoCalGas Rule 30

Rule No. 30 Sheet 1

TRANSPORTATION OF CUSTOMER-OWNED GAS

The general terms and conditions applicable whenever the Utility System Operator transports customer-owned gas, including wholesale customers, the Utility Gas Procurement Department, other end-use customers, aggregators, marketers and storage customers (referred to herein as "customers") over its system are described herein.

A. General

1. Subject to the terms, limitations and conditions of this rule and any applicable CPUC authorized tariff schedule, directive, or rule, the customer will deliver or cause to be delivered to the Utility and accept on redelivery quantities of gas which shall not exceed the Utility's capability to receive or redeliver such quantities. The Utility will accept such quantities of gas from the customer or its designee and redeliver to the customer on a reasonably concurrent basis an equivalent quantity, on a therm basis, to the quantity accepted.

2. The customer warrants to the Utility that the customer has the right to deliver the gas provided for in the customer's applicable service agreement or contract (hereinafter "service agreement") and that the gas is free from all liens and adverse claims of every kind. The customer will indemnify, defend and hold the Utility harmless against any costs and expenses on account of royalties, payments or other charges applicable before or upon delivery to the Utility of the gas under such service agreement.

3. The point(s) where the Utility will receive the gas into its intrastate system (point(s) of receipt, as defined in Rule No. 1) and the point(s) where the Utility will deliver the gas from its intrastate system to the customer (point(s) of delivery, as defined in Rule No. 1) will be set forth in the customer's applicable service agreement. Other points of receipt and delivery may be added by written amendment thereof by mutual agreement. The appropriate delivery pressure at the point(s) of T
delivery to the customer shall be that existing at such point(s) within the Utility's system or as T
specified in the service agreement.

B. Quantities

1. The Utility shall as nearly as practicable each day redeliver to customer and customer shall accept, a like quantity of gas as is delivered by the customer to the Utility on such day. 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. However, it is recognized that due to operating conditions either (1) in the fields T
of production, (2) in the delivery facilities of third parties, or (3) in the Utility's system, deliveries into and redeliveries from the Utility's system may not balance on a day-to-day basis. The Utility and the customer will use all due diligence to assure proper load balancing in a timely manner.

(Continued)

B. Quantities (Continued)

2. The gas to be transported hereunder shall be delivered and redelivered as nearly as practicable at uniform hourly and daily rates of flow. The Utility may refuse to accept fluctuations in excess of ten percent (10%) of the previous day's deliveries, from day to day, if in the Utility's opinion receipt of such gas would jeopardize other operations. Customers may make arrangements acceptable to the Utility to waive this requirement.

3. The Utility does not undertake to redeliver to the customer any of the identical gas accepted by the Utility for transportation, and all redelivery of gas to the customer will be accomplished by substitution on a therm-for-therm basis.

4. Transportation customers, including the Utility Gas Procurement Department, wholesale customers, contracted marketers, and aggregators will be provided monthly balancing services in accordance with the provisions of Schedule No. G-IMB. T

C. Electronic Bulletin Board

1. The Utility prefers and encourages customers, including the Utility Gas Procurement Department, to use Electronic Bulletin Board (EBB) as defined in Rule No. 1 to submit their transportation nominations to the Utility. Imbalance trades are to be submitted through EBB or by means of the Imbalance Trading Agreement Form (Form 6544). Use of EBB is not mandatory for transportation only customers. T

2. Transportation nominations may be submitted manually or through EBB. For each transportation nomination submitted manually, (by means other than EBB such as facsimile transmittal), a processing charge of $11.87 shall be assessed. No processing charge will apply to an EBB subscriber for nominations submitted by fax at a time the EBB system is unavailable for use by the subscriber.

D. Operational Requirements

1. Customer Representation

The customer must provide to the Utility the name(s) of any agents ("Agent") used by the customer for delivery of gas to the Utility for transportation service hereunder and their authority to represent customer.

A customer may choose only one of the following gas supply arrangements: 1) one Contractor, 2) one or multiple Agents, or 3) itself for purposes of nominating to its end-use account (OCC).

TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

D. Operational Requirements (Continued)

2. Receipt Points

Utility accepts nominations from transportation customers or their representatives at the following Receipt Points into the SoCalGas system, as referenced in Schedule No. G-BTS*:

- El Paso Pipeline at Blythe (Southern Transmission Zone)
- North Baja Pipeline at Blythe (Southern Transmission Zone)
- Transportadora de Gas Natural de Baja California at Otay Mesa (Southern Transmission Zone)
- Kern River Pipeline and Mojave Pipeline (Wheeler Transmission Zone)
- PG&E at Kern River Station (Wheeler Transmission Zone)
- Occidental of Elk Hills at Gosford (Wheeler Transmission Zone)
- Transwestern Pipeline at North Needles (Northern Transmission Zone)
- Transwestern Pipeline at Topock (Northern Transmission Zone)
- El Paso Pipeline at Topock (Northern Transmission Zone)
- Questar Southern Trails Pipeline at North Needles (Northern Transmission Zone)
- Kern River Pipeline and Mojave Pipeline at Kramer Junction (Northern Transmission Zone)
- Line 85 (California Supply)
- North Coastal (California Supply)
- Other (California Supply) D
- Storage

* Additional Receipt Points will be added as they are established in the future.

3. Backbone Transmission Capacity

Each day, Receipt Point and Backbone Transmission Zone capacities will be set at their physical operating maximums under the operating conditions for that day. The Utility will schedule nominations for each Receipt Point and Backbone Transmission Zone to the maximum operating capacity of that individual Receipt Point or Backbone Transmission Zone. The maximum operating capacity is defined as the facility design or contractual limitation to deliver gas into the Utility's system adjusted for operational constraints (i.e. maintenance, localized restrictions, and upstream delivery pressures) as determined each day.

The NAESB elapsed pro rata rules require that the portion of the scheduled quantity that would have theoretically flowed up to the effective time of the intraday nomination be confirmed, based upon a cumulative uniform hourly quantity for each nomination period affected. As such, the scheduled quantities for each shipper are subject to change in the Intraday 1 Cycle and the Intraday 2 Cycle. However, each shipper's resulting scheduled quantity for the Gas Day will be no less than the elapsed prorated scheduled quantity for that shipper.

(Continued)

(Continued)

D. Operational Requirements (Continued)

3. Backbone Transmission Capacity (Continued)

Each day, the Utility will use the following rules to confirm nominations to the Receipt Point and Backbone Transmission Zone maximum operating capacities. The Utility will also use the following rules to confirm nominations to the system capacity limitation as defined in Section F for OFO events during the Intraday 1 cycle.

Confirmation Order:

- Nominations using Firm Primary backbone transportation rights will be first; pro-rated if over-nominated*.
- Nominations using Firm Alternate backbone transportation rights within the associated transmission zone will be second ("Firm Alternate Within-the-Zone"); pro-rated if over-nominated.
- Nominations using Firm Alternate backbone transportation rights outside the associated transmission zone will be third ("Firm Alternate Outside-the-Zone"); pro-rated if over-nominated.
- Nominations using Interruptible backbone transportation rights will be fourth, pro-rated if over-nominated.
- Southern Transmission Receipt Points will not be reduced in any cycle below 110% of the Southern System minimum flowing supply requirement established by the Gas Control Department. N
|
N

Bumping Rules:

- Firm Primary rights can "bump" any Firm Alternate scheduled quantities through the Evening Cycle.
- Firm Alternate Within-the-Zone rights can "bump" Firm Alternate Outside-the-Zone scheduled quantities through the Evening Cycle.
- Firm Primary and any Firm Alternate can "bump" interruptible scheduled quantities through the Intraday 1 Cycle subject to the NAESB elapsed pro-rata rules.
- Bumping will not be allowed in the Intraday 2 Cycle.

* If the available firm capacity at a particular receipt point or within a particular transmission zone is less than the firm capacity figures stated in Schedule No. G-BTS, scheduling of firm backbone transportation capacity nominations will be pro rata within each scheduling cycle. Any nominations of firm backbone transportation rights acquired through the addition of Displacement Backbone Transmission Capacity facilities will be reduced pro rata to zero at the applicable receipt point or within the applicable transmission zone prior to other firm backbone transportation rights nominations being reduced.

(Continued)

D. Operational Requirements (Continued)

3. Backbone Transmission Capacity (Continued) T

Priority Rules: D N

a. Firm primary scheduled quantities in the Evening Cycle will have priority over a new firm primary nomination made in the Intraday 1 Cycle.
b. Firm Alternate Inside-the-Zone scheduled quantities in the Evening Cycle will have priority over a new Firm Alternate Inside-the-Zone nomination made in the Intraday 1 Cycle.
c. Firm Alternate Outside-the-Zone scheduled quantities in the Evening Cycle will have priority over a new Firm Alternate Outside-the-Zone nomination made in the Intraday 1 Cycle.
d. Interruptible scheduled quantities in the Evening Cycle will have priority over a new Interruptible nomination made in the Intraday 1 Cycle.
e. This same structure will be applied in going from Intraday 1 Cycle (Cycle 3) to Intraday 2 Cycle (Cycle 4). However, this hierarchy will not affect Intraday 3 (Cycle 5) nominations or the elapsed pro rata rule. N

4. Storage Service Capacity L

Each day, storage injection and withdrawal capacities will be set at their physical operating maximums under the operating conditions for that day and posted on the Utility's EBB. These capacities will take into account offsetting injection or withdrawal activity that effectively increase withdrawal or injection capacities. The Utility will use the following rules to limit the nominations to the storage maximums. L L,T L,T

- As necessary, withdrawal or injection allocated to the daily balancing function will be set aside and given first priority every day. L
- Nominations using Firm storage rights will have the next~~firs~~t priority, pro-rated, if necessary to the available ~~firm~~ storage capacity. L,T L
- All other nominations using Interruptible storage rights will have the lowest~~second~~ priority, pro-rated if over-nominated based on the daily volumetric price paid. L L
- On low OFO days the volume of interruptible withdrawal will be cut in half relative to the calculation on a non-OFO day. If interruptible nominations immediately prior to the low OFO were above this level, then they will be held constant through the low OFO.
- Firm storage rights can "bump" interruptible scheduled storage quantities through the Intraday 3 cycle.

Notice to bumped parties will be provided via the Transactions module in EBB. Bumping is subject to the NAESB elapsed prorata rules.

D. Operational Requirements (Continued)

5. Off-System Delivery (OSD) Services

For each flow date, the Utility will determine the quantity of capacity available for off-system deliveries. The quantity will include that available via physical redelivery from the Utility system along with displacement of forward haul flowing supplies. For each nomination cycle, the Utility customers who have contracted with the Utility for off-system delivery service may submit a nomination for such service pursuant to Schedule No. G-OSD and Section D.6. “Nominations” below, for deliveries to the PG&E system and to the Utility Transmission system’s interconnection points with all interstate and international pipelines, but excluding California-produced gas supply lines.

The following rules will be used in scheduling of Off-System Delivery Services:

- Nominations using Firm OSD rights will have first priority; pro-rated if over-nominated.
- Nominations using Interruptible OSD rights will have second priority; pro-rated if over-nominated.
- Firm OSD rights can “bump” Interruptible OSD scheduled quantities through the Intraday 1 Cycle, subject to the NAESB elapsed pro rata rules.
- Bumping of Interruptible OSD rights by Firm OSD rights will not be allowed in the Intraday 2 Cycle.
- Both Firm and Interruptible OSD rights, at any Delivery Point, can be curtailed/reduced in any cycle (subject to the NAESB elapsed pro rata rules) if, in the sole judgment of the Utility, the provision of OSD service at that Delivery Point would result in the Utility having to bring additional gas into the Utility’s system at an additional cost.
- Curtailment/reduction of Interruptible OSD nominations at any Delivery Point will be prorated at that particular Delivery Point.
- Curtailment/reduction of Firm OSD nominations at any Delivery Point will be prorated at that particular Delivery Point.

Rule No. 30 Sheet 7
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

D. Operational Requirements (Continued) L

6. Nominations

The customer shall be responsible for submitting gas service nominations to the Utility no later than the deadlines specified below.

Each nomination shall include all information required by the Utility's nomination procedures. Nominations received by the Utility will be subject to the conditions specified in the service agreements with the Utility. The Utility may reject any nomination not conforming to the requirements in these rules or in applicable service agreements. The customer shall be responsible for making all corresponding upstream nomination/confirmation arrangements with the interconnecting pipeline(s) and/or operator(s).

Evening and Intraday nominations may be used to request an increase or decrease to scheduled volumes or a change to receipt or delivery points.

Intraday nominations do not roll from day to day. L

Nominations submitted in any cycle will automatically roll to subsequent cycles for the specified flow date and from day-to-day through the end date or until the end date is modified by the nominating entity.

Nominations may be made in the following manner:

FROM	TO	
Pipeline/CA Producer	Backbone Transportation Service Contract	T
Backbone Transportation Service Contract	End User, Contracted Marketer, ESP	|
Backbone Transportation Service Contract	Citygate Pool Account	|
Backbone Transportation Service Contract	Storage Account	T
Citygate Pool Account	End User, Contracted Marketer, ESP	D
Citygate Pool Account	Citygate Pool Account	
Storage Account	End User, Contracted Marketer, ESP	

(Continued)

Rule No. 30 Sheet 8
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

D. Operational Requirements (Continued)

6. Nominations (Continued) L

FROM	TO (Continued)
Citygate Pool Account	Storage Account
Storage Account	Citygate Pool Account
Storage Account	Storage Account
Storage Account	Off-System Delivery Contract
Citygate Pool Account	Off-System Delivery Contract
End User, Contracted Marketer, ESP	Storage Account
Off-System Delivery Contract	PG&E Pipeline (at Kern River Station)
Off-System Delivery Contract	Mojave Pipeline (at Wheeler Ridge)
Off-System Delivery Contract	Mojave Pipeline (at Kramer Junction)
Off-System Delivery Contract	Kern River Pipeline (at Wheeler Ridge)
Off-System Delivery Contract	Kern River Pipeline (at Kramer Junction)
Off-System Delivery Contract	Questar Southern Trails Pipeline (at North Needles)
Off-System Delivery Contract	Transwestern Pipeline (at North Needles)
Off-System Delivery Contract	Transwestern Pipeline (at Topock)
Off-System Delivery Contract	El Paso Pipeline (at Topock)
Off-System Delivery Contract	El Paso Pipeline (at Blythe)
Off-System Delivery Contract	North Baja Pipeline (at Blythe)
Off-System Delivery Contract	Transportadora de Gas Natural de Baja California (at Otay Mesa)
Receipt Point Pool Account	Receipt Point Pool Account N
Receipt Point Pool Account	Backbone Transportation Contract N

7. Timing L

All times referred to below are in Pacific Clock Time. Requests for deadline extensions may be granted for 15 minutes only if request is made prior to the deadlines shown below. |

Timely Cycle |

Transportation nominations submitted via EBB for the Timely Nomination cycle must be received by the Utility by 9:30 a.m. one day prior to the flow date. Nominations submitted via fax must be received by the Utility by 8:30 a.m. one day prior to the flow date. Timely nominations will be effective at 7:00 a.m. on the flow date. L

(Continued)

D. Operational Requirements (Continued)

7. Timing (Continued)

Evening Cycle L

Nominations submitted via EBB for the Evening Nomination cycle must be received by the Utility by 4:00 p.m. one day prior to the flow date. Nominations submitted via fax must be received by the Utility by 3:00 p.m. one day prior to the flow date. Evening nominations will be effective at 7:00 a.m. on the flow date.

Intraday 1 Cycle

Nominations submitted via EBB for the Intraday 1 Nomination cycle must be received by the Utility by 8:00 a.m. on the flow date. Nominations submitted via fax must be received by the Utility by 7:00 a.m. on the flow date. Intraday 1 nominations will be effective at 3:00 p.m. the same day.

Intraday 2 Cycle

Nominations submitted via EBB for the Intraday 2 Nomination cycle must be received by the Utility by 3:00 p.m. on the flow date. Nominations submitted via fax must be received by the Utility by 2:00 p.m. on the flow date. Intraday 2 nominations will be effective at 7:00 p.m. the same day.

Intraday 3 Cycle

Nominations submitted via EBB for the Intraday 3 Nomination cycle must be received by the Utility by 9:00 p.m. Pacific Clock Time on the flow date. Nominations submitted via fax must be received by the Utility by 8:00 p.m. Pacific Clock Time on the flow date. Physical flow is deemed to begin at 11:00 p.m. Pacific Clock Time. L

Intraday 3 nominations are available only for firm nominations relating to the injection of existing flowing supplies into a storage account or for firm nominations relating to the withdrawal of gas in storage to meet an identified customer's usage. A customer may make Intraday 3 nominations from a third-party storage provider that is directly connected to the Utility's system or from the Utility's storage, subject to the storage provider or the Utility being able to deliver or accept the daily quantity nominated for Intraday 3 within the remaining hours of the flow day and the Utility's having the ability to deliver or accept the required hourly equivalent flow rate during the remaining hours of the flow day. Third-party storage providers will be treated on a comparable basis with the Utility's storage facilities to the extent that it can provide the equivalent service and operations.

L

TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

D. Operational Requirements (Continued)

8. Confirmation and Ranking Process L

A ranking must be received by the Utility at the time the nomination or the confirmation is submitted. The nominating party will rank its supplies and the confirming party will rank its markets. The Utility will then balance the pipeline system using the "lesser of" rule and the rankings submitted.

The ranking will automatically roll from cycle-to-cycle and day-to-day until the nomination end date, unless modified by the nominating entity.

If no ranking is submitted at the time the nomination is submitted, the Utility will assign the lowest ranking to the nomination.

The Utility will compare the nominations received for each transaction and the corresponding confirmation. If the two quantities do not agree, the "lesser of" the two quantities will be the quantity scheduled by the Utility. Subject to the Utility receiving notification of confirmed transportation from the applicable upstream pipeline(s) and/or operator(s), the Utility will provide scheduled quantities on EBB.

9. As between the customer and the Utility, the customer shall be deemed to be in control and possession of the gas to be delivered hereunder and responsible for any damage or injury caused thereby until the gas has been delivered at the point(s) of receipt. The Utility shall thereafter be deemed to be in control and possession of the gas after delivery to the Utility at the point(s) of receipt and shall be responsible for any damage or injury caused thereby until the same shall have been redelivered at the point(s) of delivery, unless the damage or injury has been caused by the quality of gas originally delivered to the Utility, for which the customer shall remain responsible. L

10. Any penalties or charges incurred by the Utility under an interstate or intrastate supplier contract as a result of accommodating transportation service shall be paid by the responsible customer.

11. Customers receiving service from the Utility for the transportation of customer-owned gas shall pay any costs incurred by the Utility because of any failure by third parties to perform their obligations related to providing such service.

L

(Continued)

(Continued)

~~E. Interruption of Service~~

~~1. The customer's transportation service priority shall be established in accordance with the definitions of Core and Noncore service, as set forth in Rule No. 1, and the provisions of Rule No. 23, Continuity of Service and Interruption of Delivery. If the customer's gas use is classified in more than one service priority, it is the customer's responsibility to inform the Utility of such priorities applicable to the customer's service. Once established, such priorities cannot be changed during a curtailment period.~~

~~2. The Utility shall have the right, without liability (except for the express provisions of the Utility's Service Interruption Credit as set forth in Rule No. 23), to interrupt the acceptance or redelivery of gas whenever it becomes necessary to test, alter, modify, enlarge or repair any facility or property comprising the Utility's system or otherwise related to its operation. When doing so, the Utility will try to cause a minimum of inconvenience to the customer. Except in cases of unforeseen emergency, the Utility shall give a minimum of ten (10) days advance written notice of such activity.~~

~~F. Nominations in Excess of System Capacity~~

~~1. The Utility System Operator's protocol for declaring an Operational Flow Order (OFO) is described in Rule No. 41. Any OFO shall apply to all customers, including wholesale customers and the Utility Gas Procurement Department.~~

~~2. The OFO period shall begin on the flow date(s) indicated by the Utility Gas Control Department. Customers shall be allowed to reduce their nominations or adjust their supply ranking in response to the OFO.~~

~~3. In the event customers fail to adequately reduce their transportation nominations, the Utility shall reduce the confirmed receipt point access nominations as defined in Section D.~~

~~4. In accordance with the provisions of Schedule No. G-IMB, Buy-Back service shall be applied separately to each OFO day. Customer meters subject to maximum daily quantity limitations will use the maximum daily quantity as a proxy for daily usage. For the Utility Gas Procurement Department, the Daily Forecast Quantity will be used as a proxy for daily usage. For core aggregators, their Daily Contract Quantity will be used as a proxy for daily usage.~~

~~5. A California Producer, with an effective California Producer Operational Balancing Agreement, Form 6452, will be subject to Schedule No. G-IMB Buy-Back service during excess nominations days (i.e., OFO days). For each OFO day, the Utility shall cash out, at the Retail Buy-Back Rate as described in Schedule No. G-IMB, all of an individual California Producer's actual deliveries that are in excess of 110% of that particular California Producer's scheduled quantities for that OFO day. The OFO day imbalance of a California Producer with an existing access agreement will be treated consistent with the terms of that access agreement.~~ ~~N~~

(Continued)

Rule No. 30 Sheet 12 T

TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

~~G. Winter Deliveries~~ L

~~The Utility requires that customers deliver (using a combination of flowing supply and storage withdrawal) at least 50% of burn over a five-day period from November through March. As the Utility's total storage inventory declines through the winter, the delivery requirement becomes daily and increases to 70% or 90% depending on the level of inventory relative to peak day minimums.~~

~~1. From November 1 through March 31 customers are required to deliver (flowing supply and storage withdrawal) at a minimum of 50% of burn over a 5-day period. In other words, for each 5-day period, the Utility will calculate the total burn and the total delivery. If the total delivery is less than 50% of the total burn, a daily balancing standby charge is applied. The daily balancing standby rate is 150% of the highest Southern California Border price during the five day period as published by Natural Gas Intelligence in "NGI's *Daily* Gas Price Index," including authorized franchise fees and uncollectible expenses (F&U) and brokerage fees. Authorized F&U will not be added to any daily stand-by balancing charge for the Utility Gas Procurement Department to the extent it is collected elsewhere. Imbalance trading may not be used to offset the delivery minimums.~~

~~a. "Burn" means usage and is defined as metered throughput or an estimated quantity such as Minimum Daily Quantity (MinDQ), as defined in Rule No. 1, for customers without automated meters, the Daily Contract Quantity for core aggregators, or the Daily Forecast Quantity for the Utility Gas Procurement Department.~~

~~b. Example five-day periods are: Nov. 1 through Nov. 5, Nov. 6 through Nov. 10, Nov. 11 through Nov. 15 and so on. November with 30 days has six 5-day periods. December, January and March with 31 days have a 6-day period at the end of the month. February has a shortened 3 or 4-day period at the end of the month. The current 5-day period will run its course fully before the implementation of the 70% daily requirement. In the event that inventories rise above the 70% daily trigger levels by 1 Bcf, then a new, 5-day period will be implemented on the following day.~~

~~c. Example calculations for determining volumes subject to the daily balancing standby rate are: if over 5 days, total burn is 500,000 therms and total deliveries (including withdrawal) are 240,000 therms, then 10,000 therms is subject to daily balancing standby rate. (50% times 500,000 minus 240,000 equals 10,000).~~ L

~~d. Example calculations in using NGI's Daily Gas Price Index for determining the daily balancing standby rate are: If for Jan. 6 through Jan. 10 the NGI Southern California Border quoted price ranges are \$2.36- 2.39, \$2.36-2.44, \$2.38-2.47, \$2.36-2.42, and \$2.37- 2.45, respectively, then the daily balancing standby rate becomes \$3.71 (\$2.47 times 150%).~~

~~e. With the exception of weekends and holidays, the Utility will use quotes from the NGI publication dated on the same day as the flow date. Weekend or holiday flow dates will use the first available publication date after the weekend or holiday.~~ L

(Continued)

~~G. Winter Deliveries (Continued)~~

~~2. When total inventory declines to the "peak day minimum + 20 Bcf trigger," the minimum daily delivery requirement increases to 70%. Customers are then required to be balanced (flowing supply plus storage withdrawal) at a minimum of 70% of burn on a daily basis. The 5-day period no longer applies since the system can no longer provide added flexibility. The daily balancing standby rate is 150% of the highest Southern California Border price per NGI's *Daily* Gas Price Index for the day (including authorized F&U and brokerage fees) and is applied to each day's deliveries which are less than the 70% requirement. Authorized F&U will not be added to any daily stand-by balancing charge for the Utility Gas Procurement Department to the extent it is collected elsewhere. In this regime interruptible storage withdrawal is cut in half subject to the scheduling priorities established in Section D.8. All Operational Hub Services contributing to the underdelivery situation (i.e., Operational Hub deliveries greater than Operational Hub receipts) are suspended. All of the requirements in this paragraph are waived for the days that an OFO is in effect.~~ L

~~a. Peak day minimums are calculated annually before November 1 as part of normal winter operations planning. The peak day minimum is that level of total inventory that must be in storage to provide deliverability for the core 1-in-35 year peak day event, firm withdrawal commitments and noncore balancing requirement.~~

~~b. Example calculations in this regime for determining volumes subject to the daily balancing standby rates are: If on January 6 total burn is 500,000 therms, and total deliveries (including withdrawal) are 300,000 therms then 50,000 therms is subject to the daily balancing standby charge (70% times 500,000 minus 300,000 equals 50,000).~~

~~c. Example calculations in using NGI's Daily Gas Price Index for daily balancing standby rates in this regime are: if for January 6 and January 7, the NGI Southern California Border quoted price ranges are $2.36-2.39 and $2.36-2.44, then the daily balancing standby rates become $3.59 (150% of 2.39) for January 6, and $3.66 (150% times 2.44) for January 7, respectively.~~ L

~~3. When total inventories decline to the "peak day minimum + 5 Bcf trigger," the minimum daily delivery requirement increases to 90%. Customers are required to be balanced (flowing supply plus storage withdrawal) at a minimum of 90% of burn on a daily basis. Similar to the 70% regime the 5-day period no longer applies. The daily balancing standby rate is charged daily and is 150% of the highest Southern California Border price per NGI's *Daily* Gas Price Index for the day (including authorized F&U and brokerage fees). Authorized F&U will not be added to any daily stand-by balancing charge for the Utility Gas Procurement Department to the extent it is collected elsewhere. In this regime there are no interruptible storage withdrawals. All Operational Hub Services contributing to the underdelivery situation (i.e., Operational Hub Service deliveries greater than Operational Hub Service receipts) is suspended. All of the requirements in this paragraph are waived for the days that an OFO is in effect.~~

L

(TO BE INSERTED BY UTILITY) ISSUED BY (TO BE INSERTED BY CAL. PUC)
ADVICE LETTER NO. 4258 **Lee Schavrien** DATE FILED Jul 15, 2011
DECISION NO. 11-03-029 Senior Vice President EFFECTIVE Oct 1, 2012
13C0 RESOLUTION NO.

Rule No. 30 Sheet 14 T

TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

~~G. Winter Deliveries (Continued)~~

~~4. Information regarding the established peak day minimums, daily balancing trigger levels and total storage inventory levels will be made available to customers on a daily basis via EBB and other customer notification media.~~ L

~~5. If a wholesale customer so requests, the Utility will nominate firm storage withdrawal volumes on behalf of the customer to match 100% of actual usage assuming the customer has sufficient firm storage withdrawal and inventory rights to match the customer's supply and demand.~~

~~6. The Utility will accept intra-day nominations to increase deliveries.~~

~~7. In all cases, current BCAP rules for monthly balancing and monthly imbalance trading continue to apply. Volumes not in compliance with the 50%, 70% and 90% minimum delivery requirements, purchased at the daily balancing standby rate, are credited toward the monthly 90% delivery requirements. Daily balancing charges remain independent of monthly balancing charges. Noncore daily balancing and monthly balancing charges go to the Purchased Gas Account (PGA). Net revenues from core daily balancing and monthly balancing charges go to the Noncore Fixed Cost Account (NFCA). Schedule No. G-IMB provides details on monthly and daily balancing charges.~~

H. Accounting and Billing

1. The customer and the Utility acknowledge that on any operating day during the customer's applicable term of transportation service, the Utility may be redelivering quantities of gas to the customer pursuant to other present or future service arrangements. In such an event, the Utility and customer agree that the total quantities of gas shall be accounted for in accordance with the provisions of Rule No. 23. If there is no conflict with Rule No. 23, the quantities of gas shall be accounted for in the following order: L

   a. First, to satisfy any minimum quantities under existing agreements.

   b. Second, after complete satisfaction of (a), then to any supply or exchange service arrangements with the customer.

   c. Third, after the satisfaction of (a) and (b), then to any subsequently executed service agreement. L

(Continued)

H. Accounting and Billing (Continued)

2. The customer agrees that it shall accept and the Utility can rely upon, for purposes of accounting and billing, the allocation made by customer's shipper as to the quality and quantity of gas, expressed both in Decatherm and therms, delivered at each point of receipt during the preceding billing period for the customer's account. If the shipper does not make such an allocation, the customer agrees to accept the quality and quantity as determined by the Utility. All quality and measurement calculations are subject to subsequent adjustment as provided in the Utility's tariff schedules or applicable CPUC rules and regulations. Any other billing correction or adjustment made by the customer or third party for any prior period shall be based on the rates or costs in effect when the event occurred and accounted for in the period they are reconciled. L

3. The Utility shall render to the customer an invoice for the services hereunder showing the quantities of gas, expressed in therms, delivered to the Utility for the customer's account, at each point of receipt and the quantities of gas, expressed in therms, redelivered by the Utility for the customer's account at each point of delivery during the preceding billing period. The Customer shall pay such amounts due hereunder within nineteen (19) calendar days following the date such bill is mailed.

4. Both the Utility and the customer shall have the right at all reasonable times to examine, at its expense, the books and records of the other to the extent necessary to verify the accuracy of any statement, charge, computation, or demand made under or pursuant to service hereunder. The Utility and the customer agree to keep records and books of account in accordance with generally accepted accounting principles and practices in the industry.

I. Gas Delivery Specifications

1. The natural gas stream delivered into the Utility's system shall conform to the gas quality specifications as provided in any applicable agreements and contracts currently in place between the entity delivering such natural gas and the Utility at the time of the delivery. If no such agreement is in place, the natural gas shall conform to the gas specifications as defined below. L

2. Gas delivered into the Utility's system for the account of a customer for which there is no existing contract between the delivering pipeline and the Utility shall be at a pressure such that the gas can be integrated into the Utility's system at the point(s) of receipt.

3. Gas delivered, except as defined in I.1 above, shall conform to the following quality specifications at the time of delivery:

L

I. Gas Delivery Specifications (Continued)

3. (Continued)

a. Heating Value: The minimum heating value is nine hundred and ninety (990) Btu (gross) per standard cubic foot on a dry basis. The maximum heating value is one thousand one hundred fifty (1150) Btu (gross) per standard cubic foot on a dry basis. L

b. Moisture Content or Water Content: For gas delivered at or below a pressure of eight hundred (800) psig, the gas shall have a water content not in excess of seven (7) pounds per million standard cubic feet. For gas delivered at a pressure exceeding of eight hundred (800) psig, the gas shall have a water dew point not exceeding 20 degrees F at delivery pressure.

c. Hydrogen Sulfide: The gas shall not contain more than twenty-five hundredths (0.25) of one (1) grain of hydrogen sulfide, measured as hydrogen sulfide, per one hundred (100) standard cubic feet (4 ppm). The gas shall not contain any entrained hydrogen sulfide treatment chemical (solvent) or its by-products in the gas stream.

d. Mercaptan Sulfur: The gas shall not contain more than three tenths (0.3) grains of mercaptan sulfur, measured as sulfur, per hundred standard cubic feet (5 ppm).

e. Total Sulfur: The gas shall not contain more than seventy-five hundredths (0.75) of a grain of total sulfur compounds, measured as sulfur, per one hundred (100) standard cubic feet (12.6 ppm). This includes COS and CS2, hydrogen sulfide, mercaptans and mono, di and poly sulfides.

f. Carbon Dioxide: The gas shall not have a total carbon dioxide content in excess of three percent (3%) by volume.

g. Oxygen: The gas shall not have an oxygen content in excess of two-tenths of one percent (0.2%) by volume, and customer will make every reasonable effort to keep the gas free of oxygen.

h. Inerts: The gas shall not contain in excess of four percent (4%) total inerts (the total combined carbon dioxide, nitrogen, oxygen and any other inert compound) by volume.

i. Hydrocarbons: For gas delivered at a pressure of 800 psig or less, the gas hydrocarbon dew point is not to exceed 45 degrees F at 400 psig or at the delivery pressure if the delivery pressure is below 400 psig. For gas delivered at a pressure higher than 800 psig, the gas hydrocarbon dew point is not to exceed 20 degrees F measured at a pressure of 400 psig. L

(Continued)

I. Gas Delivery Specifications (Continued)

3. (Continued)

j. Merchantability: The gas shall not contain dust, sand, dirt, gums, oils and other substances injurious to Utility facilities or that would cause gas to be unmarketable.

k. Hazardous Substances: The gas must not contain hazardous substances (including but not limited to toxic and/or carcinogenic substances and/or reproductive toxins) concentrations which would prevent or restrict the normal marketing of gas, be injurious to pipeline facilities, or which would present a health and/or safety hazard to Utility employees and/or the general public.

l. Delivery Temperature: The gas delivery temperature is not to be below 50 degrees F or above 105 degrees F.

m. Interchangeability: The gas shall have a minimum Wobbe Number of 1279 and shall not have a maximum Wobbe Number greater than 1385. The gas shall meet American Gas Association's Lifting Index, Flashback Index and Yellow Tip Index interchangeability indices for high methane gas relative to a typical composition of gas in the Utility system serving the area.

Acceptable specification ranges are:

* Lifting Index (IL)
  IL <= 1.06

* Flashback Index (IF)
  IF <= 1.2

* Yellow Tip Index (IY)
  IY >= 0.8

n. Liquids: The gas shall contain no liquids at or immediately downstream of the receipt point.

o. Landfill Gas: Gas from landfills will not be accepted or transported.

p. Biogas: Biogas refers to a gas derived from renewable organic sources. The gas is primarily a mixture of methane and carbon dioxide. Biogas must be free from bacteria, pathogens and any other substances injurious to Utility facilities or that would cause the gas to be unmarketable and it shall conform to all gas quality specifications identified in this Rule.

(Continued)

(Continued)

I. Gas Delivery Specifications (Continued)

4. The Utility, at its option, may refuse to accept any gas tendered for transportation by the customer or on his behalf if such gas does not meet the specifications at the time of delivery as set out in I. 2 and I. 3 above, as applicable.

5. The Utility will grant specific deviations to California production from the gas quality specifications defined in Paragraph I.3 above, if such gas will not have a negative impact on system operations. Any such deviation will be required to be filed through Advice Letter for approval prior to gas actually flowing in the Utility system.

6. The Utility will post on its EBB and/or general website information regarding the available real-time Wobbe Number of gas at identified operational locations on its system.

7. Gas monitoring and enforcement hardware and software including, but not limited to, a gas chromatograph and all related equipment, communications facilities and software, identified in Exhibit A to Schedule No. G-CPS, are required, and shall be installed at each interconnection meter site where a California Producer delivers natural gas into the Utility's gas transportation system. The gas chromatograph shall monitor non-hydrogen sulfide constituents in the gas delivered, and deny access to gas that does not comply with the gas specifications set forth in the Gas Delivery Specifications, Section I.1 or I.3 above. Compliance shall be assessed using the 4- to 8-minute monitoring interval adopted in D.07-08-029 and D.10-09-001. N

8. The gas chromatograph and all related equipment and software, identified in Exhibit A to Schedule No. G-CPS, shall monitor and enforce the gas quality specifications, using the 4- to 8-minute monitoring interval adopted in D.07-08-029 and D.10-09-001. Access shall be denied by the Utility on a non-latching basis after a second consecutive monitoring interval results in an alarm for gas which exceeds the non-hydrogen sulfide specifications. The gas chromatograph and all related equipment and software shall also enable the Utility to remotely gather and retain gas quality and alarm data. Where additional measures are necessary to promote or enhance safety, SoCalGas may request a deviation from the aforementioned monitoring interval requirements established by the CPUC.

9. For California Producers currently delivering gas into the Utility's transportation system without a gas chromatograph and all related equipment and software in place, as required in Rule No. 39, non-hydrogen sulfide constituents of gas will, on an interim basis, continue to be monitored and access denied under the methods currently in place, until such time as a gas chromatograph and all related equipment and software are installed and operational, subject to Rule No. 39 conditions. N
L

(Continued)

Rule No. 30 Sheet 19
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

J. Termination or Modification L

1. If the customer breaches any terms and conditions of service of the customer's service agreement or the applicable tariff schedules and does not correct the situation within thirty (30) days of notice, the Utility shall have the right to cease service and immediately terminate the customer's applicable service agreement.

2. If the contract is terminated, either party has the right to collect any quantities of gas or money due them for transportation service provided prior to the termination.

K. Regulatory Requirements

1. Any gas transported by the Utility for the customer which was first transported outside the State of California shall have first been authorized under Federal Energy Regulatory Commission (FERC) regulations, as amended. Both parties recognize that such regulations only apply to pipelines subject to FERC jurisdiction, and do not apply to the Utility. The customer shall not take any action which would subject the Utility to the jurisdiction of the FERC, the Economic Regulatory Administration or any succeeding agency. Any such action shall be cause for immediate termination of the service arrangement between the customer and the Utility.

2. Transportation service shall not begin until both parties have received and accepted any and all regulatory authorizations necessary for such service. L

L. Warranty and Indemnification

1. The customer warrants to the Utility that the customer has the right to deliver gas hereunder and that such gas is free from all liens and adverse claims of every kind. Customer will indemnify, defend and save the Utility harmless against all loss, damage, injury, liability and expense of any character where such loss, damage, injury, liability or expense arises directly or indirectly out of any demand, claim, action, cause of action or suit brought by any person, association or entity asserting ownership of or any interest in the gas tendered for transportation hereunder, or on account of royalties, payments or other charges applicable before or upon delivery of gas hereunder.

2. The customer shall indemnify, defend and save harmless the Utility, its officers, agents, and employees from and against any and all loss, costs (including reasonable attorneys' fees), damage, injury, liability, and claims for injury or death of persons (including any employee of the customer or the Utility), or for loss or damage to property (including the property of the customer or the Utility), which occurs or is based upon an act or acts which occur while the gas is deemed to be in the customer's control and possession or which results directly or indirectly from the customer's performance of its obligations arising pursuant to the provisions of its service agreement and the Utility's applicable tariff schedules, or occurs based on the customer-owned gas not meeting the specifications of Section I of this rule.