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April 20, 2018

Advice No. 5275-A
(U 904 G)

Public Utilities Commission of the State of California

Subject: Supplement - Expedited Advice Letter Requesting Approval of the Proposed Second Injection Enhancement Plan and Second Injection Enhancement Memorandum between the System Operator and the Gas Acquisition Department for Services to Maintain Summer Reliability Pursuant to the March 13, 2018 "Injection Required for SoCalGas Summer Reliability and Storage Inventories" Letter from CPUC Executive Director Alice Stebbins

Southern California Gas Company (SoCalGas) hereby submits for approval by the California Public Utilities Commission (Commission or CPUC): (1) a proposed Second Injection Enhancement Plan to support system reliability; (2) temporary revisions to its tariffs, applicable throughout its service territory, as shown in Attachment A; (3) the Second Injection Enhancement Memorandum (Second IEM) to document the activities and direct the manner in which employees of SoCalGas shall conduct the relationship between the SoCalGas System Operator and SoCalGas Gas Acquisition Department (Gas Acquisition) with respect to efforts to increase storage injections to support system reliability, as shown in Attachment B; and (4) SoCalGas' Summer 2018 Technical Assessment, as shown in Attachment C.

Purpose

This submission is intended to put into effect the directives contained in the March 13 and 19, 2018 letters from Executive Director Stebbins to Bret Lane, President and Chief Operating Officer of SoCalGas. In the March 13, 2018 letter, Executive Director Stebbins directs SoCalGas' Gas Acquisition Department to purchase natural gas to support storage requirements for system reliability.

This supplemental Advice Letter (AL) replaces in its entirety AL 5275, filed on March 30, 2018. This supplemental AL includes: 1) correcting an addition error and year reference in Table 2; 2) changing the withdrawal rates measurements from billion cubic feet per day (Bcfd) to million cubic feet per day (MMcfd) in Table 2; 3) clarifying that the temporary modifications to increase injection operations and injection capacity available to market have an end date of October 31, 2018; and 4) revising the end date for the temporary modifications to System Operator limits on available injection capacity provided to the market to October 31, 2018 for consistency with the other proposed measures.

Background

On March 13, 2018, the Executive Director sent a letter to Bret Lane, President and Chief Operating Officer of SoCalGas, under the subject “Injection Required for SoCalGas Summer Reliability and Storage Inventories.” The letter states that “[a]dequate natural gas inventory levels are necessary to maintain reliable delivery to both core and noncore customers during 1-in-10-year peak demand periods” and that “[g]iven the withdrawals from all storage fields during winter 2017-18 and the limited availability of the Aliso Canyon storage field due to the Public Utilities Code Section 715 Report requirements adopted December 11, 2017, overall storage inventory is critically low.” To support energy reliability for southern California, the March 13 letter directs SoCalGas to “take immediate action to increase injections at all available storage facilities” and “to immediately begin maximizing storage injections at all storage fields using the procurement capabilities of the SoCalGas Acquisition Department to support SoCalGas' storage requirement for system reliability” (Second System Reliability Directive).[1]

To accomplish this, the Executive Director directed SoCalGas to submit a Tier 2 AL “proposing an agreement between the SoCalGas System Operator and the SoCalGas Gas Acquisition Department to support SoCalGas’ storage requirements for system reliability similar to the Injection Enhancement Plan and Injection Enhancement Memorandum process approved by Resolution G-3529 (June 29, 2017).”[2]

The Executive Director further stated that SoCalGas should include the following in its AL:

- An Injection Plan based on rapidly achieving storage withdrawal capacity at the non-Aliso storage fields of 1,320 MMcfd;[3]
- Minimum month-end storage targets for the remaining months of 2018 beginning with May 2018;
- Forecasted monthly natural gas storage quantities procured by the Gas Acquisition

[1] On May 8, 2017, then CPUC Executive Director Timothy Sullivan sent a similar request to Mr. Lane. SoCalGas complied with the request, filing AL 5139 on May 19, 2017. AL 5139 was approved, in part, by Resolution G-3529 on June 29, 2017.

[2] The March 13, 2018 letter originally directed the AL to be submitted by March 20, 2018, however, the deadline was extended to March 30 per Executive Director Stebbins’ letter dated March 19, 2018.

[3] As noted in the March 13, 2018 letter, the Commission does not require that SoCalGas maintain this level of withdrawal capacity at all times. SoCalGas is authorized to use storage to meet demand, even if it means withdrawal capacity at the non-Aliso Canyon fields temporarily falls below 1,320 MMcfd. If that occurs, however, the Commission indicates that it expects SoCalGas to make effort to return storage to levels needed to support this withdrawal capacity.

Department solely for the purpose of ensuring system reliability outside of its normal business as usual procurement for core customers; and

- An estimated cost for the Gas Acquisition Department to provide these support services.

Additionally, the Executive Director directed SoCalGas to request expedited treatment by proposing a shortened protest period and time to reply to the protest, and authorized SoCalGas to submit a separate AL seeking the establishment of a memorandum account to track costs resulting from the Second Injection Enhancement Plan.[4]

As indicated in the Second System Reliability Directive, the Second Injection Enhancement Plan is intended to support "SoCalGas' storage requirements for system reliability" because "adequate natural gas inventory levels are necessary to maintain reliable delivery to both core and noncore customers during 1-in-10-year peak demand periods." The SoCalGas pipeline and storage system is a winter peaking system and does not have a 1-in-10-year design criterion for the summer operating season. SoCalGas understands that the Commission is mindful of the reliability and affordability of noncore electric generation customers in southern California. As explained below, however, forecasts indicate that there is not enough flowing supply capacity available throughout the summer season to meet customer demand *and* inject into storage.

Under existing regulations and policies, electric generation is a noncore customer and is the first user set to be curtailed, as needed, to manage system reliability. SoCalGas is also authorized to trigger Low operational flow orders (OFOs), as necessary, to maintain high levels of gas deliveries throughout the summer to promote full utilization of available receipt capacity. Although either of these measures would support the reliability of the natural gas system, they may impact noncore customers. As such, although noncore curtailment or additional Low OFOs may still be necessary, SoCalGas has identified alternative measures to support energy system reliability in its Second Injection Enhancement Plan. Based on our current forecasts and analysis, if the Commission does not approve execution of the plan identified below, it will result in SoCalGas curtailing noncore customers and triggering Low OFOs, in conjunction with the suite of options indicated below to support system reliability.

On March 30, 2018, at the direction of the Executive Director, SoCalGas filed AL 5275, and in order to expedite the AL, the Commission set a five-day protest period, with protests due April 6, 2018, and SoCalGas' reply (if necessary) due by April 11, 2018. No protests to AL 5275 were received. On April 19, 2018, Energy Division requested that SoCalGas issue a supplemental AL to address the four changes identified above. As such, and at the direction of Energy Division, SoCalGas hereby submits AL 5275-A, which replaces AL 5275 in its entirety.

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[4] *See* AL 5276, Expedited Advice Letter Requesting to Modify the Injection Enhancement Cost Memorandum Account (IECMA) Pursuant to the March 13, 2018 "Injection Required for SoCalGas Summer Reliability and Storage Inventories" letter from CPUC Executive Director Alice Stebbins.

Injection Capacity and Target Inventories

As a first step in developing an injection enhancement plan, SoCalGas assessed the injection capacity of the system. Using a forecast of available physical injection capacity, SoCalGas projected storage inventories necessary to achieve a storage withdrawal capacity at the non-Aliso storage fields of 1,320 MMcfd, as required by the Commission, and then projected target inventory levels to achieve this non-Aliso Canyon withdrawal capacity.

Maximum Physical Injection Capacity Available

SoCalGas projects monthly maximum storage injection capacities (in MMcfd) at each of the SoCalGas storage fields in the following table. Planned or unplanned outages or projects that cannot be deferred may result in short-term injection capacity reductions and will be posted to the SoCalGas ENVOY® (Envoy) website.

Table 1: Projected Monthly Maximum Storage Injection Capacities (MMcfd)

Storage Field	6/1/2018	7/1/2018	8/1/2018	9/1/2018	10/1/2018
La Goleta	40	40	40	40	40
Playa Del Rey	0	0	0	0	0
Honor Rancho	200	170	0	0	200
Aliso Canyon	410	0	0	0	0
Total System	650	210	40	40	240

Although these capacities are based on the physical capabilities of the injection of the storage fields and specific transmission facilities, actual system conditions may result in lower or higher injection capabilities. In addition, injection capacity will diminish with higher ambient temperatures, and as field reservoir pressures increase.

SoCalGas strives to maintain the Playa Del Rey storage field at full inventory, and thus its injection capacity is projected to be zero by June 2018. However, after any withdrawals from Playa Del Rey, some additional injection capacity will be available for customers to schedule injections. Injections at the La Goleta storage field are highly dependent on the reliability and operation of the Ventura Compressor Station. Therefore, any outages resulting from safety, compliance, or reliability issues at the Ventura Compressor Station may impact the injection capability at La Goleta. Further, as identified in Table 2, SoCalGas forecasts that the inventory levels at Honor Rancho will reach their maximum in August 2018. As a result, injection capacity at Honor Rancho is expected to be 0 from August 2018 until withdrawals occur.

Finally, SoCalGas anticipates having Aliso Canyon at its mandated maximum inventory of 24.6 Bcf by June, which, absent withdrawals from the facility, eliminates Aliso Canyon's injection capacity past June. This limitation reduces overall calculated system capacity and can increase the number of High OFOs triggered. SoCalGas proposes to mitigate this

Aliso Canyon limitation in the Second Injection Enhancement Plan described below by increasing the authorized inventory at Aliso Canyon and modifying the Aliso Canyon Withdrawal Protocol to use Aliso Canyon as a source of supply, which will increase injection capacity and maintain inventory levels and associated withdrawal capacity.

Target Inventories to Meet Withdrawal Capacity Per CPUC Directive for the Summer Period

SoCalGas' Summer 2018 Technical Assessment (Attachment C) includes a mass balance to examine the ability to fill storage under two pipeline supply scenarios. As explained in the Summer 2018 Technical Assessment, there is not enough flowing supply capacity available throughout the summer season to meet customer demand *and* inject into storage. This is a result of heavy drawdown of the storage fields during the latter part of the winter 2017-18 season and the continued reduction of interstate pipeline receipt capacity resulting from pipeline outages and reductions. As depicted in the Summer 2018 Technical Assessment, under a "worst case" scenario (based upon current known potential projects which may impact receipt capacity) and assuming 85% pipeline utilization, the non-Aliso Canyon storage fields will be depleted and withdrawal capacity available will be limited to what only Aliso Canyon can provide.

In order to achieve a storage withdrawal capacity at the non-Aliso storage fields of 1,320 MMcfd (per Commission directive), the storage inventories included in Table 2 can be reasonably targeted. The targets included in Table 2 assume the Summer 2018 Technical Assessment's "worst case" scenario flowing supplies and assume 95% receipt point utilization, since 85% utilization is insufficient to reach the 1,320 MMcfd level. To maintain 95% receipt point utilization would require that measures to enhance receipt point utilization be implemented – for example, daily Low OFOs or the Second Injection Enhancement Plan discussed below. Further, although the non-Aliso storage fields can achieve 1,320 MMcfd, that withdrawal capacity cannot be maintained without the use of Aliso Canyon as defined below.

Table 2: Targeted Monthly Storage Inventories with Corresponding Withdrawal Rates

Storage Field	6/1/2018		7/1/2018		8/1/2018	
	Target Inventory (Bcf)	Resulting WD Rate (MMcfd)	Target Inventory (Bcf)	Resulting WD Rate (MMcfd)	Target Inventory (Bcf)	Resulting WD Rate (MMcfd)
La Goleta	14.4	238	15.6	247	16.9	257
Playa Del Rey	1.9	302	1.9	302	1.9	302
Honor Rancho	18.8	677	24.4	823	27.0	892
Non-Aliso	35.1	1217	41.9	1372	45.8	1451
Aliso Canyon	21.9	815	24.6	869	24.6	869
Total System	**57.0**	**2032**	**66.5**	**2241**	**70.4**	**2320**

Storage Field	9/1/2018		10/1/2018		11/1/2018	
	Target Inventory (Bcf)	Resulting WD Rate (Bcfd)	Target Inventory (Bcf)	Resulting WD Rate (Bcfd)	Target Inventory (Bcf)	Resulting WD Rate (Bcfd)
La Goleta	18.1	267	19.3	277	19.5	279
Playa Del Rey	1.9	302	1.9	302	1.9	302
Honor Rancho	27.0	892	19.1	685	17.3	637
Non-Aliso	47	1461	40.3	1264	38.7	1218
Aliso Canyon	24.6	869	24.6	869	24.6	869
Total System	**71.6**	**2330**	**64.9**	**2133**	**63.3**	**2087**

As indicated in Table 2, the 1,320 MMcfd withdrawal capacity at the non-Aliso storage fields is not anticipated to be met *and* maintained throughout this timeframe. Further, it bears emphasizing that these are monthly target inventories based on the anticipated level of physical injection. SoCalGas' Gas Acquisition Department will strive to maximize injection quantities when practicable. Actual system conditions impact volumes. As noted previously, injection capacity will diminish with higher ambient temperatures, and as field reservoir pressures increase. Reaching these targets depends on the availability of sufficient supply and capacity to fill storage. The Second Injection Enhancement Plan described below supports efforts toward achieving these targets, but SoCalGas cannot guarantee the targets will be reached.

Plan to Enhance Injections to Support Summer System Reliability (Second Injection Enhancement Plan)[5]

SoCalGas has prepared target inventories through October that achieve, but do not maintain, the Commission-directed withdrawal capacity at the non-Aliso storage fields of 1,320 MMcfd. After September 2018, due to forecasted demand and limited pipeline capacity, SoCalGas projects to be below the targeted withdrawal capacity without the use of Aliso Canyon.

As directed by the Commission, SoCalGas prepared a Second Injection Enhancement Plan to promote storage injections and system reliability. Specifically, SoCalGas identified the following measures to enhance injections to meet summer customer demand and prepare storage for the winter operating season:

1. Increase the allowable inventory at Aliso Canyon to enable more system-wide injections;

[5] If necessary, SoCalGas will provide an updated plan to support winter system reliability.

2. Modify the Aliso Canyon Withdrawal Protocol to allow for more flexible use of Aliso Canyon to manage storage inventories and support reliability in conjunction with a temporary deviation to SoCalGas Rule No. 23;
3. Continue to implement temporary modifications to system operations to increase storage injections;
4. Implement temporary modifications to increase storage injection capacity available to the market; and
5. Implement temporary modifications to system operator limits on available injection capacity provided the market;

Each of these measures will help support efforts to maximize injection into the storage fields. SoCalGas believes that each of these measures should be implemented for the system to best be able to achieve the above storage inventory targets.

1. <u>Increase the allowable inventory at Aliso Canyon to enable more system-wide injections</u>

SoCalGas projects that reaching the currently-approved inventory at Aliso Canyon of 24.6 Bcf is reached in June 2018, removing the injection capacity of the facility for the rest of the summer. Not having Aliso Canyon's injection capacity available reduces system capacity, increases the likelihood of High OFOs, and will reduce the amount of gas that could enter the system on any given day as intended by the High OFO. Maintaining and utilizing the physical injection capacity of Aliso Canyon for scheduling will increase system capacity, reduce the likelihood of High OFOS, maximize the use of the available receipt point capacity, ultimately increasing the amount gas flowing into the system and further enhances the probability to maximize injections in all the storage fields.

As such, the Commission should increase the allowable inventory to a minimum of 30 Bcf at Aliso Canyon, thereby increasing the system-wide injection capacity for a greater period of time. Should the inventory at Aliso Canyon approach the 30 Bcf limit and the other storage fields are not yet full, SoCalGas may request that the Commission further increase the authorized inventory level at Aliso Canyon. The 30 Bcf figure is only for the ability to maximize supplies flowing into the system for injection in the other fields and not intended to achieve any specific withdrawal capacity to meet the reliable service of a 1-10 scenario for all core and noncore customers as stated in the March 13, 2018 letter.

2. <u>Modify the Aliso Canyon Withdrawal Protocol to allow for more flexible use of Aliso Canyon to manage storage inventories and support reliability</u>

The Commission should modify the Aliso Canyon Withdrawal Protocol to allow the System Operator to utilize Aliso Canyon withdrawals without curtailing customers to maintain and build inventory levels and associated withdrawal capacity at the other storage fields. In its March 2, 2018 letter to the Commission, SoCalGas requested the ability to immediately begin using Aliso Canyon to manage gas storage inventory and preserve withdrawal deliverability at SoCalGas' non-Aliso storage fields.[6] During this time SoCalGas operated Aliso Canyon in response to below average cold temperatures in accordance with the withdrawal protocol as acknowledged by the Commission in its letter dated March 3, 2018.[7] The Commission should revise the Aliso Canyon Withdrawal Protocol to allow SoCalGas to use Aliso Canyon as a source of supply, as necessary this summer, to increase injection at the other fields and maintain inventory levels and associated withdrawal capacity at the other storage fields. Absent Aliso Canyon supply, forecasts indicate that a temporary deviation to Rule No. 23 would be required to effectuate the curtailment of noncore customers to preserve storage inventory to achieve the 1,320 MMcfd of non-Aliso Canyon withdrawal capacity.

3. SoCalGas will Implement the Following Temporary Modifications to Increase Injection Operations

SoCalGas is making efforts to enhance injections by moving forward with the following modifications to its system operations:

Release of Injection Capacity Reserved for Balancing:
SoCalGas' current rules allow for the storage injection capacity to be reserved and set aside for use in the balancing function. The current amount set aside for this function is 200,000 dekatherms (Dth). As of April 9, 2018, in an effort to increase storage injections, SoCalGas began releasing 100,000 Dth of the injection capacity reserved for balancing on Cycle 1 for customers to use.

Deferral of Projects that Impact Injection Operations:
To the extent feasible, shutdowns or operational deviations that impact injection capacity will be rescheduled or deferred until such time that SoCalGas' storage inventory targets have been met. Any shutdowns or work related to equipment reliability, safety or compliance will not be considered for deferral. Commission authorization of this modification is proposed to be temporary and, unless an extension is sought, will end October 31, 2018.

4. SoCalGas will Implement the Following Temporary Modifications to Increase Injection Capacity Available to Market

Every month before Bid Week,[8] the System Operator will set a portion of the storage injection capacity allocated to the system balancing function for injection nominations for the following month in Cycle 1. This quantity will be made available on a reasonable best

[6] See March 2, 2018 Letter from Rodger Schwecke to Edward Randolph. Available at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Safety/Letter%20to%20Edward%20Randolph_CPUC%20from%20Rodger%20Schwecke_SoCalGas-March%202.pdf
[7] See March 3, 2018 Letter from Edward Randolph to Rodger Schwecke. Available at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Safety/Letter%20to%20Rodger%20Schwecke.pdf
[8] Bid Week is the five business days preceding the first of the month.

efforts basis considering operational limitations and will be posted on Envoy. As mentioned above, having injection available in Aliso Canyon will promote the ability to make injection capacity available at the first of the month. Gas Acquisition will use reasonable best efforts to utilize the quantity made available.

The day before a gas flow day, the System Operator will determine whether additional injection capacity allocated to the system balancing function above what was made available for the month can be made available for injection nominations in Cycle 1. If additional capacity can be made available for Cycle 1, the additional capacity will be reflected in the Net Storage Injection Capacity value on the Capacity Utilization Page on Envoy. The System Operator will use its reasonable best efforts to make this additional quantity available for the remainder of the gas day. Gas Acquisition will use its reasonable best efforts to utilize the quantity made available.

Each flow day morning, the System Operator will determine whether additional injection capacity allocated to the system balancing function can be made available for injection nominations in Cycle 3. If additional capacity can be made available for Cycle 3, the additional capacity will be reflected in the Net Storage Injection Capacity value on the Capacity Utilization Page on Envoy. This additional quantity will be made available on a reasonable best efforts basis for the remainder of the gas day. Gas Acquisition will use reasonable best efforts to utilize the quantity made available. Commission authorization of this modification is proposed to be temporary and, unless an extension is sought, will end October 31, 2018.

5. Temporary Modifications to System Operator Limits on Available Injection Capacity Provided the Market Requiring Commission Approval

SoCalGas requests the authority to make available to the market injection capacity that exceeds the physical injection capacity of the storage fields on days when gas is being withdrawn in support of demand effectively increasing the amount of gas that can be requested to be injected. Presently, the System Operator is limited to make available and post on Envoy for customer nominations, only the physically available injection capacity of the storage fields, adjusted for any outages at the fields. On some days, injection capacity is available beyond the physical limits due to under scheduling of gas into the system, and/or when customers schedule withdrawal. Making that additional capacity available may increase the amount of gas delivered into the system and thereby increase injection capability.

SoCalGas does not propose to modify the physical injection capacity which is based on actual operating conditions. Under this request for authority, SoCalGas would add an additional variable to the Forecasted System Capacity calculation to account for additional injection capacity, as described above. Currently, SoCalGas' Rule No. 41 describes the Forecasted System Capacity as the following:

Forecasted System Capacity = Forecasted Sendout + Physical Storage Injection Capacity + Off-System Scheduled Quantities[9]

The proposed formula would be:

Forecasted System Capacity = Forecasted Sendout + Physical Storage Injection Capacity + Off-System Scheduled Quantities + <u>Incremental Injection Capacity</u>

Where:

Incremental Injection Capacity = Prior Cycle Scheduled Withdrawal + Withdrawal Capacity Used for Balancing

This will effectively increase the overall system capacity to enable more flowing supplies to be scheduled on the system for injection. SoCalGas does not anticipate an increase in High OFOs, or late cycle system nomination reductions as a result of this requested modification, because the new Forecasted System Capacity value will be increased by the Incremental Injection Capacity. Commission authorization of this modification is proposed to be temporary and, unless an extension is sought, will end October 31, 2018.

<u>Purchases Made Solely for System Reliability</u>

The March 13, 2018 letter from Executive Director Stebbins authorizes SoCalGas to submit a separate AL seeking the establishment of a memorandum account to track costs resulting from the Injection Enhancement Plan.[10] Pursuant to this authorization SoCalGas is concurrently submitting AL 5276 to revise its Injection Enhancement Cost Memorandum Account (IECMA) to "track costs resulting from the operational changes described in this letter."[11] However, it can be difficult to distinguish (1) purchases that are made solely for the purposes of system reliability and (2) Gas Acquisitions normal business procuring on behalf of core customers. To distinguish these purchases, SoCalGas proposes that, until the Aliso Canyon Withdrawal Protocol is modified to allow for use of the gas in Aliso Canyon to support core customer needs, injected quantities into Aliso Canyon be deemed for system reliability and purchases made by Gas Acquisition for this purpose are deemed to have been on behalf of the System Operator.

As such, SoCalGas seeks approval to track or include costs associated with procurement of these supplies in the System Reliability Memorandum Account, which records certain costs associated with the purchase and delivery of gas to sustain operational flows on the SoCalGas/SDG&E system.

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[9] SoCalGas Rule No. 41: https://socalgas.com/regulatory/tariffs/tm2/pdf/41.pdf.

[10] *See* AL 5276, Expedited Advice Letter Requesting to Modify the Injection Enhancement Cost Memorandum Account (IECMA) Pursuant to the March 13, 2018 "Injection Required for SoCalGas Summer Reliability and Storage Inventories" letter from CPUC Executive Director Alice Stebbins.

[11] Id.

<u>SoCalGas' Gas Acquisition Department efforts to support system reliability</u>

<u>Gas Acquisition Plans for Core Customer Reliability, As Mandated by The Commission</u>

Gas Acquisition has been directed by the Commission to primarily purchase and plan for SoCalGas' core customers.[12] Gas Acquisition does so by attempting to minimize commodity costs, while providing reliable supplies to core customers by optimizing the use of its authorized assets (firm injection, withdrawal, and parking and loaning) throughout the year. Although Gas Acquisition strives to fill core storage through the summer to help meet core customers' winter needs, its allocated storage inventory exceeds the capacity available in the non-Aliso Canyon storage fields and the Aliso Canyon mandated maximum inventory that is available but constrained by the Aliso Canyon Withdrawal Protocol. Therefore, Gas Acquisition cannot meet its November 1, 2018 storage inventory target.

<u>Gas Acquisition Will Have to Alter Its Procurement and Injection Plan to Meet the New Commission Directive to Support Noncore Reliability</u>

To effectuate the Commission's long-standing directive to focus on core reliability, Gas Acquisition uses its allocated storage inventory primarily for winter reliability for retail core customers. After each winter season, Gas Acquisition re-builds depleted storage inventory throughout the spring/summer injection season to reach required inventory targets in preparation for the coming winter season. With a mandated maximum inventory at Aliso Canyon, Gas Acquisition's method of providing for retail core winter reliability is constrained and more difficult. In response, Gas Acquisition's base procurement plan is to maximize use of its allocated firm injection rights and balancing tolerances including during system High OFOs in order to build inventory this summer.

In this AL, the SoCalGas System Operator has stated that, beginning April 9, 2018, it will post daily on scheduling Cycle 1 a portion of its system firm injection reserved for balancing to be available for nomination, and will not reduce this number through the remainder of the gas day. This will provide additional reliability for Gas Acquisition to fill available storage inventory by the end of the injection season.

In order to reach the summer targeted storage inventories forth in this AL, Gas Acquisition intends to accelerate injections to the extent additional system firm injection rights become available. Gas Acquisition estimates that it will need to accelerate procurement of up to

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[12] *See* Decision (D.) 94-03-076 at 1: "SoCalGas currently procures gas on behalf of core [] customers, and transports and stores gas for core customers." *See also* D.07-12-019, mimeo., at 105 (Findings of Fact 19) ("Since Gas Acquisition will no longer be performing system reliability and balancing services, under Remedial Measure 16, as adopted in D.98-03-073, unrestricted communications between Gas Operations and Gas Acquisition are no longer permitted.") and at 116 (Ordering Paragraph 15) ("Applicants' proposal that responsibility for managing any minimum flow requirements for system reliability be transferred from the Gas Acquisition Department to the System Operator and paid for by all customers, is granted.")

8 Bcf of natural gas to reach the targeted storage inventories identified Table 2.

SoCalGas Requests to Modify its Injection Enhancement Cost Memorandum Account to Track the Incremental Costs Associated with the Commission's Second System Reliability Directive[13]

It is difficult to forecast the costs that may be incurred by Gas Acquisition associated with obtaining these accelerated supplies for injection to support system reliability. Gas Acquisition will likely use a variety of gas supply tools, some of which may only be sporadically available and/or subject to operational and market limitations, to increase system receipts during the summer. These tools may include negotiated services from upstream pipelines and late-cycle supply arrangements with suppliers, as well as other tools.[14] Gas Acquisition will use reasonable best efforts to use these additional tools to attempt to fill the incremental inventory needed at the lowest cost. These reasonable best efforts will be complicated by Gas Acquisition's lack of knowledge under the affiliate rules and remedial measures of noncore imbalances, LUAF, and other system operational information that cannot be shared with Gas Acquisition. Gas Acquisition's efforts will also be impacted by natural gas procurement protocols, such as, for example, weekend day-ahead trading on Friday for equal daily volumes on Saturday, Sunday, and Monday.

Gas Acquisition estimates that accelerating procurement of up to 8 Bcf of natural gas to meet the inventory targets to support of system reliability will result in incremental costs of approximately $4 to $8 million.[15]

Gas Acquisition may create separate accounts for incremental injections that result from the System Reliability Directive with the purpose of helping to track volumes and associated costs of gas supplies that have been accelerated. On a bi-weekly basis, Gas Acquisition proposes to review results from implementing these additional measures during ongoing conference calls with the Office of Ratepayer Advocates, Energy Division, and The Utility Reform Network.

Second Injection Enhancement Memorandum (IEM) Between Gas Acquisition and the System Operator

The March 13 Letter directs SoCalGas to propose "an agreement between the SoCalGas Acquisitions System Operator and the SoCalGas Gas Acquisition Department to support SoCalGas' storage requirements for system reliability similar to the Injection Enhancement

[13] Pursuant to Second System Reliability Directive, a revised Injection Enhancement Cost Memorandum Account (IECMA) is presented for Commission approval in a separate advice filing, AL 5276.
[14] Due to the market sensitive nature of these potential tools, Gas Acquisition does not provide specificity at this time in order to try to obtain or negotiate the use of these tools at the lowest possible cost.
[15] Calculated based on the assumption that the approximate cost would be $0.50 to $1 per dekatherm.

Plan and Injection Enhancement Memorandum process approved by Resolution G-3529."

SoCalGas proposes the Commission approve the attached Second IEM to document the activities and direct the manner in which SoCalGas System Operator and Gas Acquisition employees will interact to effectuate the Second Injection Enhancement Plan (Attachment B). The attached Second IEM, like the first, addresses SoCalGas' proposed actions, including the period of the Second IEM, identified support activities, and the tracking of costs. This Second IEM is in lieu of the execution of any contract between the operating and functional departments within SoCalGas to implement the directive.

Tariff Modifications

To implement the Enhanced System Operator Injection Capacity Limits included in the Injection Enhancement Plan described above, SoCalGas includes a revised Rule No. 41 as Attachment A. This modification is temporary, consistent with the Injection Enhancement Plan, and will be removed from the tariff after October 31, 2018.

Rule No. 41, Section 4 is revised to include an additional variable in the Forecasted System Capacity calculation called "Increment Injection Capacity" and to include a definition for that new variable. Modifications to Rule No. 41 are shown in redline as follows:

A High OFO is issued if Forecasted System Capacity<On-system Scheduled Quantities

Where,

Forecasted System Capacity = Forecasted Sendout + Physical Storage Injection Capacity + Off-System Scheduled Quantities <u>+ Incremental Injection Capacity (through Oct. 31, 2018)</u>

<u>and,</u>

<u>Incremental Injection Capacity = Prior Cycle Scheduled Withdrawal + Withdrawal Capacity Used for Balancing</u>

Protest

At the direction of the Energy Division, the protest period for this AL is closed.

Effective Date

SoCalGas believes that this filing is subject to Energy Division disposition, and should be classified as Tier 2 (effective after staff approval) pursuant to General Order (GO) 96-B.

SoCalGas respectfully requests that this filing be approved and made effective March 13, 2018, which is the date of the Second System Reliability Directive.[16]

Notice

A copy of this AL is being sent to SoCalGas' GO 96-B service list and the Commission's service lists for I.17-02-002, I.17-03-002, and A.14-12-017. Address change requests to the GO 96-B service list should be directed by electronic mail to tariffs@socalGas.com or call 213-244-2837. For changes to all other service lists, please contact the Commission's Process Office at 415-703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

Ronald van der Leeden
Director – Regulatory Affairs

Attachments

[16] Because of the likelihood of the targets being approved and Gas Acquisition's responsibilities to help meet those targets, Gas Acquisition plans to begin acquiring incremental supplies for storage injections in April.

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No. **SOUTHERN CALIFORNIA GAS COMPANY (U 904G)**

Utility type:	Contact Person: Ray B. Ortiz
☐ ELC ☒ GAS	Phone #: (213) 244-3837
☐ PLC ☐ HEAT ☐ WATER	E-mail: ROrtiz@semprautilities.com

EXPLANATION OF UTILITY TYPE	(Date Filed/ Received Stamp by CPUC)
ELC = Electric GAS = Gas PLC = Pipeline HEAT = Heat WATER = Water	

Advice Letter (AL) #: 5275-A

Subject of AL: Supplement - Expedited Advice Letter Requesting Approval of the Proposed Second Injection Enhancement Plan and Second Injection Enhancement Memorandum between the System Operator and the Gas Acquisition Department for Services to Maintain Summer Reliability Pursuant to the March 13, 2018 “Injection Required for SoCalGas Summer Reliability and Storage Inventories” Letter from CPUC Executive Director Alice Stebbins

Keywords (choose from CPUC listing): Storage, Agreements, Procurement, Contracts, Reliability

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☒ One-Time ☐ Other

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #:
None

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL[1]: N/A

Does AL request confidential treatment? If so, provide explanation: No

Resolution Required? ☐ Yes ☒ No   Tier Designation: ☐ 1 ☒ 2 ☐ 3

Requested effective date: 3/13/18   No. of tariff sheets: 3

Estimated system annual revenue effect: (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: Rule No. 41 and TOCs

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: None

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division	**Southern California Gas Company**
Attention: Tariff Unit	**Attention: Ray B. Ortiz**
505 Van Ness Ave.,	**555 West 5th Street, GT14D6**
San Francisco, CA 94102	**Los Angeles, CA 90013-1011**
EDTariffUnit@cpuc.ca.gov	**ROrtiz@semprautilities.com**
	Tariffs@socalgas.com

[1] Discuss in AL if more space is needed.

ATTACHMENT A
Advice No. 5275-A

Cal. P.U.C. Sheet No.	Title of Sheet	Cancelling Cal. P.U.C. Sheet No.
Revised 54912-G	Rule No. 41, UTILITY SYSTEM OPERATION, Sheet 2	Revised 51671-G
Revised 54913-G	TABLE OF CONTENTS	Revised 54515-G
Revised 54914-G	TABLE OF CONTENTS	Revised 54911-G

Rule No. 41 Sheet 2
UTILITY SYSTEM OPERATION

(Continued)

STRUCTURE, PROCEDURES, AND PROTOCOLS (Continued)

4. (Continued)

Cycle	**Quantity Used for OFO Calculation**
1) Timely	Prior Flow Day - Evening Cycle Scheduled Quantity
2) Evening*	Current Flow Day - Timely Cycle Scheduled Quantity
3) Intraday 1	Current Flow Day - Evening Cycle Scheduled Quantity
4) Intraday 2	Current Flow Day - Intraday 1 Cycle Scheduled Quantity

A High OFO may be issued only if the level of quantities, from the table above, exceeds the forecasted system capacity. System linepack will not be part of the formula used to determine when a High OFO shall be issued. The conditions for issuing a High OFO are summarized below.

A High OFO is issued if Forecasted System Capacity < On-system Scheduled Quantities.

Where,

Forecasted System Capacity = Forecasted Sendout
+ Physical Storage Injection Capacity
+ Off-System Scheduled Quantities
+ Incremental Injection Capacity (through October 31, 2018) N

and,

Incremental Injection Capacity = Prior Cycle Scheduled Withdrawal + Withdrawal Capacity Used for Balancing N

* The Utility will provide a minimum one-hour notice prior to the Evening Cycle nomination deadline when calling an Evening Cycle High OFO.

(Continued)

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(Continued)

RULES (continued)

TABLE OF CONTENTS

The following listed sheets contain all effective Schedules of Rates and Rules affecting service and information relating thereto in effect on the date indicated thereon.

(Continued)

ATTACHMENT B

Advice No. 5275-A

SoCalGas Second Injection Enhancement Memorandum

SOCALGAS SECOND INJECTION ENHANCEMENT MEMORANDUM

Southern California Gas Company (SoCalGas), executes this Second Injection Enhancement Memorandum (Second IEM) to document the activities and direct the manner in which employees of SoCalGas, a public utility gas company regulated by the Public Utilities Commission of the State of California (CPUC), shall conduct the relationship between the SoCalGas System Operator[1] and the Gas Acquisition Department (Gas Acquisition) to maximize storage injection to support system reliability, as directed by the CPUC.[2] This Second IEM is in lieu of execution of a contract by SoCalGas (between the operating and functional departments within SoCalGas) to implement the CPUC's directive.

1. Background. On March 13, 2018, the Executive Director of the CPUC sent a letter to SoCalGas directing SoCalGas to file a Tier 2 Advice Letter "proposing an agreement between the SoCalGas System Operator and the SoCalGas Gas Acquisition Department to support SoCalGas' storage requirements for system reliability similar to the Injection Enhancement Plan and Injection Enhancement Memorandum process approved by Resolution G-3529 (June 29, 2017)."

2. Proposed Injection Enhancement Plan Tools. The CPUC directed SoCalGas' Gas Acquisition Department to purchase natural gas to support SoCalGas' storage requirement for system reliability. To facilitate increases to storage, the System Operator and Gas Acquisition will undertake actions as follows:

   Period: The commencement date for the efforts addressed in this Second IEM is retroactive to March 13, 2018. The term of this Second IEM shall continue for each day from the commencement date through and including September 30, 2018.

   Support Activities: Every month before Bid Week, the System Operator will set a portion of the storage injection capacity allocated to the system balancing function for injection nominations for the following month in Cycle 1. This quantity will be made available on a best efforts basis considering operational limitations and will be posted on Envoy. Gas Acquisition will use reasonable best efforts to utilize the quantity made available.

   The day before a gas flow day, the System Operator will determine whether additional injection capacity allocated to the system balancing function above what was made available for the month can be made available for injection nominations in Cycle1. If additional capacity can be made available for Cycle 1, the additional capacity will be reflected in the Net Storage Injection Capacity value on the Capacity Utilization Page on Envoy. The System Operator will use its reasonable best efforts to make this additional quantity available for the remainder of the gas day. Gas Acquisition will use its reasonable best efforts to utilize the quantity made available.

   Each flow day morning, the System Operator will determine whether additional injection capacity allocated to the system balancing function can be made available for injection nominations in Cycle 3. If additional capacity can be made available for Cycle 3, the additional capacity will be reflected in the Net Storage Injection Capacity value on the Capacity Utilization Page on Envoy. This additional

[1] The System Operator is sometimes referred to internally as the "California Energy Hub" or the "Operational Hub."
[2] See March 13, 2018 letter from Alice Stebbins, Executive Director of the CPUC to Bret Lane, President and Chief Operating Officer of SoCalGas ("By this letter, I am directing SoCalGas to immediately begin maximizing storage injections at all storage fields using the procurement capabilities of the SoCalGas Acquisition Department to support SoCalGas' storage requirement for system reliability.")

quantity will be made available on a best efforts basis for the remainder of the gas day. Gas Acquisition will use reasonable best efforts to utilize the quantity made available.

Costs: Incremental costs associated with the Second IEM will be recorded in the Injection Enhancement Cost Memorandum Account.[3]

Regulatory approval: This Second IEM will be submitted to the CPUC by Advice Letter and will not become effective until approved by the CPUC. In the event the CPUC does not approve this Second IEM, or imposes terms unacceptable to SoCalGas, this Second IEM will be null and void.

Based upon the foregoing, this Second IEM sets forth the commitment and guidelines by which employees of SoCalGas will interact to maximize storage injections to support system reliability, as directed by the CPUC. All such activity will be conducted in accordance with the terms and conditions of SoCalGas' tariffs, and other applicable rules and regulations.

Date of execution: March 30, 2018

[3] *See* Advice No. 5276, Expedited Advice Letter Requesting to Modify the Injection Enhancement Costs Memorandum Account (IECMA).

ATTACHMENT C

Advice No. 5275-A

SoCalGas Summer 2018 Technical Assessment

SOUTHERN CALIFORNIA GAS COMPANY SUMMER 2018 TECHNICAL ASSESSMENT

March 30, 2018

Executive Summary

This technical assessment provides a forecasted outlook of system reliability during the coming summer months, and partially this upcoming winter, and analyzes the associated risks to energy reliability during these periods. For this analysis, SoCalGas analyzed the following: pipeline capacity available to bring gas into the system, the forecasted summer demand, available system capacity given the forecasted summer demand, and the forecasted winter storage inventory.

In assessing system reliability risks for the upcoming summer months, SoCalGas calculated the maximum system-wide capacity range available to serve end-use customers this summer to be 3.8 – 3.9 billion cubic feet per day (BCFD), *with Aliso Canyon Storage Field*[1] which is currently restricted to specific requirements for withdrawal by the California Public Utility Commission (CPUC). This analysis takes into consideration the various existing and potential outages and the operating restrictions on gas transmission and storage assets. *Without the use of Aliso Canyon*, this range is reduced to 3.3 – 3.4 BCFD. SoCalGas also projects this summer's peak demand forecast to be 3.5 BCFD, which is above the estimated maximum system-wide capacity without the use of Aliso Canyon. This analysis demonstrates that with current system conditions, it is likely that SoCalGas will need to withdraw from Aliso Canyon to meet the peak summer demand forecast, in addition to withdrawals from the other storage fields to meet non-peak demands.

To prepare for the 2018-19 winter season, SoCalGas also performed a preliminary analysis of projected storage injection and inventory through the summer. Using demand forecast data prepared for the 2016 California Gas Report (CGR), the projected SoCalGas capacity to receive pipeline supplies, and an estimate of storage field inventory levels on April 1, SoCalGas finds that the maximum system storage inventory that can be reached by November 1 is "worst case" 13 billion cubic feet (BCF) and "best case" 68 BCF. To reach the Commission's requirement of 1,320 million cubic feet per day (MMcfd) of withdrawal capacity[2] from the non-Aliso Canyon storage fields, SoCalGas would need a winter storage

[1] SoCalGas is currently operating Aliso Canyon pursuant to the CPUC's "Aliso Canyon Withdrawal Protocol" dated November 11, 2017, which specifies that withdrawal from the facility may only occur to prevent EG curtailment that may place the reliability of the electric grid at risk, or to prevent the curtailment of core or noncore non-EG customers.

[2] See March 13, 2018, Letter from Executive Director Alice Stebbins to Bret Lane, President and Chief Operating Officer of SoCalGas, under the Subject "Injection Required for SoCalGas Summer Reliability and Storage Inventories."

inventory of 43 BCF in those storage fields. As a result, SoCalGas will need to implement measures to enhance storage injections and preserve inventory to meet winter inventory targets.

System Reliability Assessment of Summer Months

The CPUC has not mandated a summer design standard for the SoCalGas system. This is partly because the SoCalGas system is a winter peaking system, and service to the core customers is not at risk in the summer season. Although noncore customers are fully interruptible pursuant to the Commission-approved SoCalGas Tariff Rule No. 23, the Commission and SoCalGas have recognized supply and operating constraints placed upon the electric grid balancing authorities in SoCalGas' service territory (California Independent System Operator [CAISO], Los Angeles Department of Water and Power [LADWP], and Imperial Irrigation District [IID]) and understand the importance of uninterrupted service to local electric generating (EG) plants in southern California. This is further confirmed by the CPUC in its March 13th letter that in which it stated: "Adequate natural gas inventory levels are necessary to maintain reliable delivery to both core and noncore customers during a 1-in-10-year peak demand periods."[3]

In assessing reliability in the upcoming summer months, SoCalGas analyzed the supply outlook for the system and the peak demand forecast. These are addressed in turn, below.

Supply Outlook

Available Flowing Pipeline Supplies and Storage Withdrawal Capacities

SoCalGas determined ranges of flowing pipeline supplies and storage withdrawal capacities by analyzing "best" and "worst" case scenarios. Under a "best case" scenario, only Line 235-2 between the Newberry and Adelanto compressor stations and Line 3000 between the Colorado River and Newberry compressor station would remain out of service during the summer.[4] Line 4000 would continue to experience a temporary pressure reduction and the current associated capacity reduction during these months.

Under a "worst case" scenario, in addition to the "best case" pipeline outages, Line 4000 between Newberry compressor station and the Cajon Pass would be removed from service for remediation, and segments of transmission Line 5000 would be potentially removed from service between Whitewater and Moreno Stations. Line 2000's rights-of-way (ROW) on the Morongo Band of Mission Indians previously expired, however the expiration occurred after initiation of this assessment and the minor capacity reduction of 30 MMcfd in the Blythe subzone is not included in this assessment.

In addition to the outages and restrictions discussed above, SoCalGas factored in that customers do not typically fully balance their supply with their demand even given SoCalGas' balancing rules. A review of

[3] See March 13, 2018, Letter from Executive Director Alice Stebbins to Bret Lane, President and Chief Operating Officer of SoCalGas, under the Subject "Injection Required for SoCalGas Summer Reliability and Storage Inventories."

[4] Line 2000 on the Southern System has been operating at reduced pressure since 2011, thereby reducing the receipt capacity at Blythe to 1,010 million cubic feet per day (MMcfd). While Line 3000 may return to service during the summer operating season, the outage of Line 235-2 and pressure limitations on Line 4000 will still restrict volumes from either North Needles or Topock to 270 MMcfd.

scheduled deliveries from the last 5 years shows that customers have used on average 80% of interstate receipt capacity. This reduced receipt capacity is consistent with a CPUC Energy Division Staff proposal in the SB 380 modeling framework that uses an assumed level of supply equal to 85% of the receipt capacity. Given these considerations, SoCalGas has adopted the assumption of 85% in the capacity calculations in this report for all supplies except for local California production which is assumed at current production rate.

Using the scenario information outlined above, the resulting “best” and “worst” case receipt capacities are detailed below in Tables 1 and 2.

Table 1
“Best Case” Available Flowing Pipeline Supplies

Receipt Point	Capacity/Supply (MMcfd)	Details
North Needles	270	Reduced receipt capacity due to Line 235 outage and Line 4000 temporary pressure reduction.
Topock	0	No receipt capacity due to Line 3000 outage.
Kramer Junction	600	Increased capacity due to reduced receipt capacity at North Needles.
Blythe	1,010	
Otay Mesa	200	Otay Mesa has a firm receipt capacity of 400 MMcfd, but is limited by the total 1,210 MMcfd receipt capacity of the Southern System. 200 MMcfd represents the remaining capacity to receive firm supply. Historically, little supply has been delivered at Otay Mesa.
Wheeler Ridge/Kern River Station	765	
California production	60	SoCalGas’ firm receipt capacity is reduced from 310 MMcfd to 210 MMcfd following the derating of pipeline in the Line 85 Zone. However, local California producers are currently utilizing only approximately 60 MMcfd of that capacity.
Total	2,905	
Assume 85% pipeline utilization	**2,478**	

Table 2
“Worst Case” Available Flowing Pipeline Supplies

Receipt Point	Capacity/Supply (MMcfd)	Details
North Needles	0	No receipt capacity due to Line 235 and Line 4000 outage.
Topock	0	No receipt capacity due to Line 3000 outage.
Kramer Junction	700	Increased capacity due to lost receipt capacity at North Needles.
Blythe	800	Reduced receipt capacity due to the potential for pipeline outages on the southern system.

Otay Mesa	150	Historically, little supply has been delivered at Otay Mesa, and only 150 MMcfd of capacity is available on the upstream pipelines supplying the receipt point in the summer operating season.
Wheeler Ridge/Kern River Station	765	
California production	60	SoCalGas' firm receipt capacity is reduced from 310 MMcfd to 210 MMcfd following the derating of pipeline in the Line 85 Zone. However, local California producers are currently utilizing only approximately 60 MMcfd of that capacity.
Total	2,475	
Assume 85% pipeline utilization	**2,113**	

SoCalGas has labeled the capacities shown in Table 2 as "worst case," based upon current known potential projects which may impact receipt capacity. However, unexpected outages on the transmission system, such as those resulting from third-party damage and safety related conditions, may still occur throughout the summer season, further reducing receipt capacity beyond the level projected in Table 2.

For this assessment, based on current storage field withdrawal capacities, SoCalGas assumed that 2.12 BCFD of withdrawal capacity would be available during the peak summer season with the use of Aliso Canyon. Without Aliso Canyon, withdrawal capacity is reduced to 1.32 BCFD. These withdrawal capabilities are dependent on having sufficient inventory already in storage to sustain these withdrawal capacities; however, it is likely that it will be difficult to maintain and/or build adequate storage inventory during the summer which may place the winter gas reliability at risk.

Peak Summer Demand Forecast and System Capacity Calculation

For the upcoming summer season, the forecast level of total system demand is 3.5 BCFD as itemized by customer type as shown below Table 3:

Table 3

Forecast Customer Demand, Summer 2018

Customer Type	Summer Demand (BCFD)
Core	0.770
Noncore, Non-Electric Generation (EG)	0.770
Noncore Electric Generation (EG) [1]	1.971
Total	3.511

[1] Derived from 2017 peak summer demand incorporating planned retirements and additions of electric generation resources. The 2017 peak EG demand event correlated to a 1-in-10 year electric temperature condition.

SoCalGas also completed the following analysis to determine how much SoCalGas' system can sustain of the above calculated demand using hydraulic simulations of its gas transmission and storage system under both the "best" and "worst" case pipeline supply scenarios described in Tables 1 and 2. These capacities are also segregated by customer type in Table 4 below.

Table 4
Summer 2018 System Capacity

	"Best Case" Pipeline Supplies		"Worst Case" Pipeline Supplies	
Customer Type	With Aliso Canyon Supply	Without Aliso Canyon Supply	With Aliso Canyon Supply	Without Aliso Canyon Supply
Core	0.770	0.770	0.770	0.770
Noncore, Non-EG	0.770	0.770	0.770	0.770
Noncore EG	2.369	1.860	2.283	1.731
Total	3.909	3.400	3.823	3.271

Based on the forecast summer 2018 demand and system capacity, SoCalGas able to meet forecast peak day demand under a "best case" and "worst case" scenario with the use of Aliso Canyon. Without Aliso Canyon, SoCalGas is unable to meet forecast peak day demand under either a "best case" or "worst case" scenario.

Note that in all scenarios, the system capacity is always less than the sum of the available pipeline and storage supplies. This is a result of the system hydraulics. Customer demand is not constant over the course of the day, particularly with the electric generation customer type, and gas supplies from interstate pipelines travel slowly across the pipeline network. Those supplies simply cannot meet the changing customer demand in time before minimum operating pressures are reached, and are also scheduled on a ratable basis based on daily expected demand rather than hourly peaks. SoCalGas' storage fields are closer to the customer demand center in the Los Angeles Basin than the interstate pipeline receipt points, and are the "flex supply" available to meet imbalances between the scheduled pipeline supplies and intraday customer demand.

Likewise, when customer demand drops off, gas supplies must also be reduced to avoid overpressuring the pipeline system. Once again, storage supplies serve the "flex supply" purpose, and are reduced by SoCalGas' Gas Control department to keep the pipeline supplies flowing. In theory, SoCalGas can also begin injecting gas supply into its storage fields if the pipeline supplies far exceed the customer demand even with all withdrawal reduced to zero. However, as system-wide injection capacity is diminished, it may become increasingly difficult to achieve high levels of pipeline utilization consistently through the summer season.

System Reliability Assessment for 2018-2019 Winter

While the summer season is known as a peak electric generation demand period, the summer season also is when SoCalGas prepares for the upcoming winter season by injecting gas supply into storage for use during the winter season.[5] This is even more critical base on the CPUC's statement in its March 13th letter to maintain inventory to provide reliable delivery to both core and non-core in a 1-in-10-year condition. To do so over the winter period would require significant additional inventory in Aliso Canyon be achieved to maintain system withdrawal capacities needed to meet the 1-in-10 year scenario. SoCalGas has not addressed what that inventory level requirement is and will look to supplement this report soon.

Using public demand forecast data published in the 2016 CGR workpapers for the summer season (April through October 2018, average temperature with base hydro condition), a projection of expected storage inventory levels on April 1 (47.5 BCF), and estimates for injection capacity at each field, SoCalGas performed a mass balance examining the ability to fill storage under both the "best" and "worst" case pipeline capacity scenarios. This mass balance is presented below in Table 5.

Table 5
Monthly Storage Injection Assessment (CGR Average Temperature with Base Hydro) (MMCF)

	April-18	May-18	June-18	July-18	August-18	September-18	October-18
"BEST CASE" SCENARIO							
CGR Demand	74550	68169	65580	74276	75020	77340	74555
Pipeline Supply, 85%	74348	76826	74348	76826	76826	74348	76826
Storage Injection [1]	-203	8526	8768	2550	1806	-2993	2231
Month-End Storage Inventory (BCF) [2]	47.30	55.82	64.59	67.14	68.95	65.95	68.18
"WORST CASE" SCENARIO							
CGR Demand	74550	68169	65580	74276	75020	77340	74555
Pipeline Supply, 85%	67973	70238	67973	70238	70238	63383	65495
Storage Injection [1]	-6578	2069	2393	-4038	-4782	-13958	-9060
Month-End Storage Inventory (BCF) [2]	40.92	42.99	45.38	41.35	36.56	22.61	13.55

1 Storage injection is the lesser of the available supply or the available injection capacity (negative numbers represent withdrawal).
2 Combined potential capacity is 73 BCF.

SoCalGas experienced heavy use of the Honor Rancho, La Goleta, and Playa del Rey storage fields during the latter part of the winter 2017-18 season as documented in the March 2, 2018 letter to the Energy Division.[6] With reduced injection capacity following the implementation of tubing-only operations at the storage fields and the loss of pipeline receipt capacity, under either of the two pipeline scenarios,

[5] SoCalGas Operations does not currently purchase and store any gas supply for the use of any customer. SoCalGas' Gas Acquisition department purchases supplies for storage only for the SoCalGas retail core and the SDG&E wholesale core market segment, excluding those core customers served by Core Transport Agents as part of a Core Aggregation Transportation program (CAT) and other wholesale providers.
[6] Available at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Safety/Letter%20to%20Edward%20Randolph_CPUC%20from%20Rodger%20Schwecke_SoCalGas-March%202.pdf

SoCalGas expects that the inventory capacity will not be fully utilized before the start of the winter heating season on November 1. Under the "best case" pipeline capacity scenario, this results in a maximum withdrawal capacity for the winter season of approximately 2.3 BCFD with Aliso Canyon, assuming no injections after November 1. This amount is reduced to approximately 1.4 BCFD without the use of Aliso Canyon. This is approximately equal to the withdrawal capacities necessary to provide the system capacities identified in Table 4. However, peak withdrawal capacities diminish as actual inventory levels diminish and should not be considered available over an entire summer or winter period.

Under the "worst case" pipeline capacity scenario, there is not enough flowing supply capacity available throughout the summer season to meet customer demand and inject additional gas into storage at the rates necessary to meet the winter season storage withdrawal rates as directed by the CPUC. SoCalGas projects that under this "worst case" scenario, inventory will reach only 13.6 BCF by the end of the summer season (pre-November 1). Without curtailments and/or greater utilization of Aliso Canyon to meet demand and maximize system storage inventory, under this scenario, fields other than Aliso Canyon will be fully depleted, and Aliso Canyon will be only at approximately 50% of its current CPUC-authorized inventory capacity (24.6 BCF). If this occurs, the withdrawal capacity available will be limited to what only Aliso Canyon can provide which is estimated at approximately 574 MMcfd given the low inventory level and other storage field operating conditions.

With such a severe reduction in receipt capacity under the "worst case" scenario, SoCalGas would explore measures to increase receipt point utilization and, as a result, that pipeline utilization may be higher than the 85% assumed. Assuming SoCalGas could maintain 95% of the receipt point utilization, which corresponds to a 5% daily balancing requirement and maximizing storage injection capability, the season-ending inventory would be increased to approximately 63 BCF. While this is still less than full inventory, it provides a greater level of reliability for the winter season, resulting in a maximum withdrawal capacity for the winter season of approximately 2.1 BCFD with withdrawals from Aliso Canyon. This amount is reduced to approximately 1.3 BCFD without the use of Aliso Canyon. Using supply from Aliso Canyon to meet summer demand and allowing utilization of pipeline receipt capacity to build or retain inventory at the other fields will drive the greatest amount of injection capacity being available and increase reliability.

Conclusion

This technical assessment provides preliminary forecasts of the upcoming summer and winter season and indicates that there is a need to enact measures to support system reliability. For the upcoming summer season, SoCalGas forecasts that it will be able to meet peak day demand under a "best case" or "worst case" scenario, so long as Aliso Canyon is available. Without Aliso Canyon, SoCalGas' system appears unable to meet peak day demand under either scenario.

For the 2018-19 winter season, to reach the Commission's requirement of 1,320 million cubic feet per day (MMcfd) of withdrawal capacity[7] from the non-Aliso Canyon storage fields, SoCalGas would need a winter storage inventory of 43 BCF in those storage fields. SoCalGas projects that it can reach 68 BCF total inventory under the "best case" scenario, but forecasts that a "worst case" scenario may result in inventories of 13 BCF.

[7] See March 13, 2018, Letter from Executive Director Alice Stebbins to Bret Lane, President and Chief Operating Officer of SoCalGas, under the Subject "Injection Required for SoCalGas Summer Reliability and Storage Inventories."