SOUTHERN CALIFORNIA GAS COMPANY SUMMER 2021 TECHNICAL ASSESSMENT

April 1, 2021

Executive Summary

SoCalGas has prepared this technical assessment to provide a forecasted outlook of system reliability during the coming summer months, assess the preparedness of the system for this upcoming winter, and analyze the associated risks to energy reliability during these periods. For this assessment, SoCalGas analyzed the following: (1) potential pipeline capacity available to bring gas into the system, (2) the forecasted summer demand, (3) potential available system capacity to serve demand, and (4) the forecasted storage inventory for the following winter season. In performing this analysis, this assessment takes into consideration various existing and potential outages and the operating restrictions on gas transmission and storage assets.

SoCalGas has sufficient capacity to serve the forecast summer peak demand of 3.26 billion cubic feet per day (BCFD). Total system capacity in the peak period was found to be 3.89 BCFD with the use of Aliso Canyon and 3.33 BCFD without the use of Aliso Canyon. Consistent with the Commission's July 23, 2019 Aliso Canyon Withdrawal Protocol,[1] SoCalGas may use Aliso Canyon if "there is an imminent and identifiable risk of gas curtailments created by an emergency condition that would impact public health and safety or result in curtailments of electric load that could be mitigated by withdrawals from Aliso Canyon."[2]

SoCalGas also performed a preliminary analysis of projected storage injection and resulting inventory through the summer to prepare for the 2021-22 winter season. Using demand forecast data prepared for the 2020 California Gas Report (CGR), projected SoCalGas capacity to receive pipeline supplies, projected injection and withdrawal capacities at the storage fields, and an estimate of storage field inventory levels on April 1, SoCalGas finds that only 66.8 billion cubic feet (BCF) of underground storage inventory can be reached by November 1 under a "best case" supply assumption at 85% receipt point utilization during an average temperature condition with a base hydro summer season. The current maximum allowable system storage inventory of 84.4 BCF[3] can be achieved at the end of the summer season with tighter balancing requirements and the assumption this would increase receipt point utilization to 90% during all summer months.

However, under a "worst case" supply scenario, even assuming an optimistic 95% utilization for all summer months during an average temperature condition with base hydro, available supplies are insufficient. In order to achieve the November monthly minimum inventory levels specified in the Aliso

[1] Aliso Canyon withdrawal is currently restricted to specific requirements specified in and pursuant to the CPUC's Aliso Canyon Withdrawal Protocol dated July 23, 2019.

[2] Aliso Canyon Withdrawal Protocol condition number 4.

[3] This assumes a Playa del Rey typical maximum inventory of 1.9 BCF.

Canyon Withdrawal Protocol, approximately 14.0 BCF of noncore curtailment over the summer season would be needed.

During a cold temperature condition with dry hydro, the ability to fill the storage fields decreases and cannot reach full capacity in the "best case" under any utilization assumption and increases necessary curtailment in the "worst case".

If receipt capacity is trending toward this "worst case", SoCalGas may need to take action to further enhance storage injections, preserve inventory to meet winter inventory targets, and/or place greater restrictions on the use of storage in the 2021-22 winter season to support noncore demand.

<u>System Reliability Assessment of Summer Months</u>

SoCalGas does not have a summer design standard. 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 CPUC-approved SoCalGas Tariff Rule No. 23 and San Diego Gas & Electric Company (SDG&E) Gas Rule No. 14, the CPUC and SoCalGas/SDG&E have recognized that supply and operating constraints placed upon the electric grid balancing authorities[4] in the utilities' service territory can place electric reliability at risk, and understand the importance of working to maintain service to local electric generation (EG) plants in southern California.

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

Supply Outlook, Available Flowing Pipeline Supplies and Storage Withdrawal Capacities

The SoCalGas/SDG&E gas transmission system is nominally designed to receive up to 3.78 BCFD of flowing supply on a firm basis. This means that if customers deliver that much supply to the SoCalGas system, and there is sufficient customer demand, then SoCalGas can redeliver that gas supply to end-use customers.[5] Supplies delivered to the SoCalGas system, however, do not reach these maximum receipt levels for a variety of reasons, including that customers may choose to use SoCalGas' balancing service rather than deliver supplies, California production has declined over time, system demand frequently does not require maximum delivery of supply, or flowing supplies may not be available due to weather patterns or maintenance impacting the interstate pipelines upstream of the SoCalGas system. Additionally, planned and unplanned pipeline outages can reduce receipt capacity.

In order to calculate this upcoming season's potential system capacity to serve customer demand, assumptions must be made regarding the available supply. The peak summer demand period is expected to occur around August, so SoCalGas determined ranges of potential available flowing pipeline supplies by analyzing "best" and "worst" case scenarios for this period. The "best case" scenario assumes that Line 4000 and Line 3000 are shut-in during the Line 4000 validation digs and potential remediation, and limited gas supply is available at the Otay Mesa receipt point. The "worst case" scenario also assumes that Line 4000 and Line 3000 are shut-in but that no supply is available at Otay Mesa.

[4] California Independent System Operator (CAISO), Los Angeles Department of Water and Power (LADWP), and Imperial Irrigation District (IID).

[5] Customer demand may also be required to be in a specific location, such as on the Southern System in order to receive the full receipt capacity of 1,210 million cubic feet per day (MMCFD) at Blythe and Otay Mesa.

In addition to the outages and restrictions above, SoCalGas took into consideration in its analysis that customers do not typically fully balance their supply with their demand given SoCalGas' balancing rules. Reviewing scheduled deliveries shows that customers have historically used on average 85% of available interstate receipt capacity. In situations with significant infrastructure outages and limited storage supply, however, SoCalGas would require tighter balancing and expect to see higher capacity utilization as a result.

Given these considerations, for the purpose of this peak day capacity calculation, SoCalGas has adopted a peak day utilization assumption of 85% for the "best case" supply scenario and 90% for the "worst case" supply scenario for all supplies except for local California production, which is assumed at the current production rate.[6]

Using the scenario information outlined above, the resulting "best" and "worst" case receipt capacities during the peak summer period, detailed below in Tables 1 and 2, are almost identical due to percent utilization and assumption limitations (there are only two pipelines impacted in the anticipated peak month of August in both the "best case" and "worst case" illustrative supply scenarios).

Table 1. "Best Case" Available Flowing Pipeline Supplies

Receipt Point	**Capacity/Supply (MMCFD)**	**Details**
North Needles	350	Reduced receipt capacity due to temporary pressure reduction and operating pressures of Line 235-2.
Topock	0	No receipt capacity due to Line 3000 and Line 4000 outages.
Kramer Junction	520	Limited by northern zonal capacity due to supply from North Needles.
Blythe	980	Reduced receipt capacity due to loss of pipeline on Southern System.
Otay Mesa	150	Expected level of supply available due to EG demand in Mexico.
Wheeler Ridge & Kern River Station	765	
California Production	70	Current level of local California production.
Total	**2,835**	
Assume 85% pipeline utilization	**2,420**	

[6] In Energy Division's final Scenarios Framework in I.17-02-002, adopted by the CPUC on January 4, 2019, Energy Division used an 85% utilization factor for certain aspects of its analysis. SoCalGas believes that 85% is more appropriate for that framework given the planning horizons used in the framework versus the single operating season used in this technical assessment.

Table 2. "Worst Case" Available Flowing Pipeline Supplies

Receipt Point	**Capacity/Supply (MMCFD)**	**Details**
North Needles	350	Reduced receipt capacity due to temporary pressure reduction and operating pressures of Line 235-2.
Topock	0	No receipt capacity due to Line 3000 and Line 4000 outages.
Kramer Junction	520	Limited by northern zonal capacity due to supply from North Needles.
Blythe	980	Reduced receipt capacity due to loss of pipeline on Southern System.
Otay Mesa	0	No receipt due to EG demand in Mexico.
Wheeler Ridge & Kern River Station	765	
California Production	70	Current level of local California production.
Total	**2,685**	
Assume 90% pipeline utilization	**2,424**	

The capacities shown in Tables 1 and 2 are based on 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, could still occur throughout the summer season, further reducing receipt capacity beyond the level projected.

For this assessment, based on current storage field withdrawal capacities and the supplies assumed in Tables 1 and 2, SoCalGas assumed that 1.47 BCFD ("best case") and 1.34 BCFD ("worst case") of inventory withdrawal capacity would be available during the peak summer season with the use of Aliso Canyon. Without Aliso Canyon, withdrawal capacity is reduced to 0.91 BCFD ("best case") and 0.83 BCFD ("worst case"). These withdrawal capabilities are dependent on having sufficient inventory levels in storage to sustain these withdrawal capacities. The lower withdrawal rates available under the "worst case" supply assumption reflects the lower levels of storage inventory that could be attained by the peak summer demand period given the reduced pipeline supplies. The estimated withdrawal and injection rates incorporate impacts from regulated assessments, well inspections, and storage field maintenance that will be occurring throughout the year.

Peak Summer Demand Forecast and System Capacity Calculation

For the upcoming summer season, the forecasted level of total system demand is approximately 3.26 BCFD as shown in Table 3, itemized by customer type as:

Table 3. Summer 2021 Forecasted Customer Demand

Customer Type	**Summer Demand (BCFD)**
Core	0.776
Noncore, Non-EG	0.770
Noncore, EG*	1.718
Total	3.264

* 2020 CGR forecast for summer 2021.

Using the values reflected in Table 3, SoCalGas analyzed how much of this forecasted demand the system can sustain using hydraulic simulations of its gas transmission and storage system, with and without utilizing Aliso Canyon. With available storage withdrawals considered, the total supply (pipeline receipts and storage withdrawal) available under the "best" and "worst" case scenarios are 3.89 BCFD and 3.76 BCFD with the availability of Aliso Canyon and 3.33 BCFD and 3.25 BCFD without.[7]

Based on the forecasted summer 2021 demand and system capacity, SoCalGas will be able to meet forecast peak day demand under a "best case" supply scenario, and support demand up to approximately 3.89 BCFD and 3.33 BCFD with and without the use of Aliso Canyon, respectively. In the "worst case" supply scenario, SoCalGas could support a sendout up to approximately 3.76 BCFD and 3.25 BCFD with and without the use of Aliso Canyon. Note that the summer peak demand forecast is just slightly greater than capacity calculated under the "worst case" supply without the use of Aliso Canyon; given this small difference, it's likely that SoCalGas could support the peak summer demand forecast under this scenario with little to no noncore curtailment.

System Reliability Assessment for 2021-2022 Winter

While the summer season is a peak electric generation demand period, the summer season is also when SoCalGas prepares for the upcoming winter season by injecting gas supply into storage for the following winter season.[8]

SoCalGas used the public demand forecast data published in the 2020 CGR workpapers for the summer season (April through October 2021) average temperature condition with base hydro and cold temperature condition with dry hydro for the mass balance. The mass balance was determined by a projection of the expected storage inventory levels on April 1 (55.1 BCF in the "best case" and 51.1 BCF in the "worst case") along with the most current withdrawal and injection capacities expected at each field through the summer season to examine the ability to fill storage under both the "best" and "worst" case supply scenarios.

The mass balance assessments assumed receipt point utilizations depending upon which assets are likely in service. For months with high levels of pipeline supply assumed available, SoCalGas used a utilization factor of 85% corresponding to historical behavior. However, as system-wide injection capacity is diminished, it may become increasingly difficult to receive high levels of pipeline supply consistently through the summer season.

The "best" and "worst" case scenarios are illustrative and reflect potential conditions in the identified months. SoCalGas takes no position or makes no warranty regarding the likelihood of either scenario. Pipeline supply for the "best" and "worst" case reflect foreseeable outages due to various assumed validation digs, in-line inspections, hydrotests, and valve replacements over the summer months. The "best case" supply assumptions consider the shortest reasonable outage for potential summer impacts and assumes potential increases to pipeline capacity when pipelines are returned to service. In the

[7] There is no significant difference in supply between the "best case" and "worst case" supply scenarios due to the utilization factor of 85% in the "best case" and 90% in the "worst case".

[8] SoCalGas Operations does not 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.

"worst case," validation digs are assumed to impact pipelines for longer periods of time and the results from in-line inspections are assumed to cause further reduction of receipt capacity via extended outage periods or pressure reductions. Additionally, the "worst case" assumes more pipelines are subject to validation digs than in the "best case." Both cases assume a reasonable schedule of projects. Under both the "best case" and "worst case" scenarios, SoCalGas analyzed different levels of receipt point utilization depending on the forecasted available supply. These utilization factors differ from the those used in assessing the peak day capacities because the mass balance is a seasonal assessment, spanning all 214 days of the summer season. SoCalGas performed four mass balance scenarios for the 2020 CGR average temperature condition with base hydro (**Table 4**): (1) "best case" supplies at 85% utilization, (2) "best case" supplies at 90% utilization, (3) "worst case" supplies at 95% in May and July where forecasted supplies were less than 2 BCFD and 90% utilization for the remaining months, (4) "worst case" supplies with 95% utilization for all months. Values shown are in million cubic feet (MMCF). Storage injection (Inj) and excess supply values are positive and storage withdrawal (WD) and supply shortfall values are negative.

Table 4. Monthly Storage Injection Assessment (CGR Average Temperature with Base Hydro) (MMCF)

		2021						
		APR	MAY	JUN	JUL	AUG	SEP	OCT
(1) "Best Case"	Supply Utilization	85%	85%	85%	85%	85%	85%	85%
	CGR Demand	74,160	66,557	63,960	73,191	77,624	73,830	74,245
	Pipeline Supply	68,783	73,243	72,608	73,243	75,028	72,608	79,771
	Storage Inj (+) / WD (-)	-5,378	6,686	8,648	52	-2,596	-1,223	5,526
	Excess (+) / Short (-)	0	0	0	0	0	0	0
	Month End Inv. (BCF)	49.75	56.44	65.08	65.13	62.54	61.32	66.84
(2) "Best Case"	Supply Utilization	90%	90%	90%	90%	90%	90%	90%
	CGR Demand	74,160	66,557	63,960	73,191	77,624	73,830	74,245
	Pipeline Supply	72,705	77,424	76,755	77,424	79,314	76,755	84,336
	Storage Inj (+) / WD (-)	-1,455	10,867	12,795	1,863	1,581	2,925	698
	Excess (+) / Short (-)	0	0	0	2,370	109	0	9,392
	Month End Inv. (BCF)	53.67	64.54	77.33	79.20	80.78	83.70	84.40
(3) "Worst Case"	Supply Utilization	90%	95%	90%	95%	90%	90%	90%
	CGR Demand	74,160	66,557	63,960	73,191	77,624	73,830	74,245
	Pipeline Supply	68,655	49,879	67,305	64,457	75,129	72,705	51,414
	Storage Inj (+) / WD (-)	-5,505	-15,870	3,345	-3,995	0	0	0
	Excess (+) / Short (-)	0	-808	0	-4,739	-2,496	-1,125	-22,832
	Month End Inv. (BCF)	45.62	29.75	33.09	29.10	29.10	29.10	29.10
(4) "Worst Case"	Supply Utilization	95%	95%	95%	95%	95%	95%	95%
	CGR Demand	74,160	66,557	63,960	73,191	77,624	73,830	74,245
	Pipeline Supply	72,353	49,879	70,928	64,457	79,182	76,628	54,149
	Storage Inj (+) / WD (-)	-1,808	-16,678	6,968	-7,254	1,558	2,798	-7,609
	Excess (+) / Short (-)	0	0	0	-1,481	0	0	-12,487
	Month End Inv. (BCF)	49.32	32.64	39.61	32.35	33.91	36.71	29.10

Under the "best case" supply scenario (1) for average temperature condition with base hydro, SoCalGas does not expect to have sufficient capacity and supply to fill its storage fields by the end of the summer season at the historical utilization rate of 85%. To fill all storage fields to the current total maximum capacity (84.4 BCF), a 90% utilization factor is needed as shown in supply scenario (2), reflecting tighter balancing requirements. In fact, this calculation shows excess pipeline supply of 11.9 BCF over the summer season at 90% utilization, most of which could potentially be stored at Aliso Canyon but for the Commission's inventory limitation of 34 BCF at that field.

Under the "worst case" supply scenario (3), available pipeline supply is insufficient to meet forecasted demand. SoCalGas projects approximately 32.0 BCF of noncore curtailment over the summer season to maintain the storage fields' respective November 1 inventory minimums to protect core reliability going into the winter season. Even assuming that SoCalGas could maintain a 95% receipt point utilization factor every day through the entire summer season as shown in supply scenario (4), which corresponds to a continuous 5% daily balancing requirement, all storage fields only reach their November 1 minimum inventories by October and approximately 14.0 BCF of noncore curtailment over the summer season is still required.

Note that the minimum inventory shown in the mass balances is only 29.1 BCF since the current Playa Del Rey storage inventory is 1.5 BCF, which is only 0.4 BCF short of the November 1 minimum inventory.

Furthermore, when the storage fields enter the winter season at minimum inventory levels, there may be significant noncore curtailments required throughout the entire winter season to protect core reliability and maintain minimum inventory levels.[9]

The storage inventory deficit is exacerbated when considering a cold temperature condition with dry hydro (**Table 5**) where the monthly demand increases by about 70 – 220 MMCFD.

Table 5. Monthly Storage Injection Assessment (CGR Cold Temperature with Dry Hydro) (MMCF)

		2021						
		APR	MAY	JUN	JUL	AUG	SEP	OCT
"Best Case"	Supply Utilization	90%	90%	90%	90%	90%	90%	90%
	CGR Demand	80,640	71,424	66,720	77,717	82,832	76,860	76,384
	Pipeline Supply	72,705	77,424	76,755	77,424	79,314	76,755	84,336
	Storage Inj (+) / WD (-)	-7,312	6,000	10,035	-294	-3,519	-105	7,952
	Excess (+) / Short (-)	-623	0	0	0	0	0	0
	Month End Inv. (BCF)	47.81	53.81	63.85	63.56	60.04	59.93	67.88
"Worst Case"	Supply Utilization	95%	95%	95%	95%	95%	95%	95%
	CGR Demand	80,640	71,424	66,720	77,717	82,832	76,860	76,384
	Pipeline Supply	72,353	49,879	70,928	64,457	79,182	76,628	54,149
	Storage Inj (+) / WD (-)	-7,216	-14,810	4,208	-4,208	0	0	0
	Excess (+) / Short (-)	-1,072	-6,735	0	-9,053	-3,650	-233	-22,235
	Month End Inv. (BCF)	43.91	29.10	33.31	29.10	29.10	29.10	29.10

[9] For instance, if inventory levels only reach the November month end minimum inventory of 29.50 BCF by November 1, no withdrawal would be available for the month of November 2021.

In a "best case" supply scenario the total storage inventory is only expected to reach 67.2 BCF, about 17.2 BCF short of the current maximum capacity even with utilization optimistically at 90% for all months. In a "worst case" supply scenario with 95% utilization for all months, approximately 43.0 BCF of noncore curtailment is needed throughout the summer season to maintain the November 1 minimum inventory level.

Conclusion

This technical assessment provides forecasts of the 2021 summer and winter seasons and indicates that there may be a need to enact measures to support system reliability. SoCalGas estimates that it will be able to meet the forecasted summer peak day demand under both "best case" and "worst case" supply assumptions, even without supply from Aliso Canyon. However, SoCalGas does not expect to completely fill storage inventory to the current maximum allowable capacity under the "best case" supply assumption in preparation for the winter 2021-22 season unless balancing requirements are tightened. Under the "worst case" supply assumption, SoCalGas expects to be on a net inventory withdrawal and is projected to end the summer season at the November 1 minimum inventory levels, even with tighter balancing requirements. This may result in greater restrictions on the use of storage supply to support noncore demand, and corresponding noncore customer curtailment during the winter season to preserve inventory and associated withdrawal capacity for core customer reliability.