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Aliso Canyon Risk Assessment Technical Report
Summer 2019

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May 20, 2019

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EXECUTIVE SUMMARY

The Southern California Gas (SoCalGas) system continues to operate at less than full capacity due to significant pipeline outages and continuing restrictions on use of the Aliso Canyon natural gas storage facility. Pipeline outages will continue through much of the summer, but pipelines may return to service later in the summer, which will increase capacity. The reduction in capacity caused by the current pipeline outages creates a threat to electric reliability in summer 2019 similar to the threat posed in summer 2018, which could result in customers being asked to reduce their electricity use. With the high number of pipeline outages, it may be difficult for SoCalGas to fill storage to a level sufficient to ensure energy reliability throughout the coming winter. If the pipelines return to service, this threat could be diminished.

This assessment is the seventh in a series of short-term assessments launched after the 2015 Aliso Canyon natural gas leak. It addresses the electric reliability impact of the extensive pipeline outages and of operating Aliso Canyon at less than full capacity and focuses only on the short-term season ahead.[1] The report was developed by the Aliso Canyon Technical Assessment Group, which is composed of technical experts and staff from the California Public Utilities Commission (CPUC), the California Energy Commission (Energy Commission), the California Independent System Operator (California ISO), and the Los Angeles Department of Water and Power (LADWP).

These seven reports are intended to provide short-term analysis and recommendations regarding SoCalGas system reliability. Long-term analysis and recommendations will be handled in other proceedings or reports. For example, the Legislature directed the CPUC to consider the feasibility of minimizing or eliminating the use of the Aliso Canyon storage facility while maintaining energy reliability, and the CPUC opened an Order Instituting Investigation (I.17-02-002) to examine the long-term viability of the Aliso Canyon gas storage facility.[2] In 2017, former Governor Edmund G. Brown Jr. asked for a plan to phase out use of the facility within 10 years.

The challenges this summer stem primarily from continuing outages on three backbone transmission pipelines. Current available pipeline capacity of 2,355 million cubic feet per day (MMcfd) is less than the 2,655 MMcfd available summer 2018, but the increase to 2,705 MMcfd in July 2019, is similar to summer 2018. The report examines three cases: base, pessimistic, and optimistic. The difference between the base, pessimistic and optimistic cases is the return to service date of pipelines. The base case assumes that pipelines return to service and are removed from service based on currently published schedules. The optimistic case does not have an impact on peak summer demand because the increase in capacity does not occur until the fall. Additionally, new Division of Oil, Gas, and Geothermal Resources (DOGGR) regulations require semiannual storage field shut-ins for testing and inventory verification. To implement these new regulations, SoCalGas scheduled each storage field to be shut-in for verification during the shoulder season in April/May and again in September/October/November. These shut-ins reduce opportunities for storage field injection.

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[1] It is important to note that this report is designed to address reliability, not the potential cost impacts of gas system constraints.

[2] See http://www.cpuc.ca.gov/AlisoOII/ for information on the CPUC Aliso Canyon Order Instituting Investigation.

Table 1: Assessment Group Base, Pessimistic and Optimistic Case Results

MMcfd	Summer 2019 Supply Capacity								
	Base			Pessimistic		Optimistic			
	June 1-June 30	July 1-Aug 8	Aug 9 +	June 1-June 30	July 1+	June 1-June 30	July 1 - Aug 8	Aug 9 - Oct 31	Nov 1 +
Pipeline	2,355	2,705	2,785	2,355	2,705	2,355	2,705	2,785	3,085
Storage	680	680	680	680	680	680	680	680	680
Total System	3,035	3,385	3,465	3,035	3,385	3,035	3,385	3,465	3,765

Source: Staff Analysis

The summer 1-in-10-year peak day[3] forecast gas demand of 3,368 MMcfd can be met by the base case supported demand of 3,385 MMcfd in July and 3,465 MMcfd anticipated August 9. The system capacity is calculated without Aliso Canyon. One caveat is that the projected supported demand is based on a July 1, 2019, non-Aliso storage inventory projection and the corresponding withdrawal capability. A lower inventory could make the outlook worse while a higher inventory could make the outlook better. If the electric system was curtailed to the minimum amount needed to avoid blackouts, the total gas system requirement could be reduced to 2,806 MMcfd as shown in Table 2.[4] Minimum generation has declined steadily over the last few years.

In summary, Southern California electric reliability can be maintained on a 1-in-10-year electric peak day, assuming 100 percent transmission import utilization and the availability of non-gas-fired generation, such as pumped storage hydro or battery storage. This conclusion remains true even when electricity transmission import utilization drops to 85 percent, after July 1, 2019 when pipeline capacity is expected to increase to 2,705 MMcfd. Using non-Aliso Canyon storage fields to meet the peak day may be sufficient unless the July 1 inventory is too low to provide the necessary withdrawal capability. If the system is under stress, SoCalGas can withdraw from Aliso Canyon provided it complies with the terms of the Aliso Canyon Withdrawal Protocol (Withdrawal Protocol).[5]

[3] The term *1-in-10-year* represents the warmest condition expected to occur once in 10 years and is used for planning capacity needed to serve noncore customers. The 1-in-10 year peak day is most likely to occur in July through September.

[4] The analysis focuses on curtailment to electric generation because this class of noncore customers is the first to be curtailed under SoCalGas Rule 23 tariff and comprises the largest demand during the summer.

[5] The Aliso Canyon Withdrawal Protocol and subsequent clarifying documents can be found here: http://cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/11.2Protocol%20PUBLIC%20UTILITIES%20COMMISSION.PDF. Clarifications: http://cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/WithdrawalProtocolClarification_2017-12-21.docx.pdf. March 3, 2018, Letter from Edward Randolph: http://cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Safety/Letter%20to%20Rodger%20Schwecke.pdf.

The authors emphasize, however, that operating the system at minimum levels curtails electric generators and leads to increased costs. There is also no guarantee that the California ISO and LADWP would be able to secure the necessary electricity imports to move the system to minimum generation, especially on short notice. The purpose of calculating minimum generation is not so that SoCalGas can plan to curtail the generators. Rather, it is done so that SoCalGas, the electric balancing authorities, and the regulatory agencies know how large of a cut the combined electric-gas system can sustain before electric reliability is jeopardized so they can develop actions to reduce risk.

Table 2: 1-in-10 Demand at Forecast versus Minimum Electric Generation Levels

Summer Demand (MMcfd)	1-in-10 Year Peak Day Forecast Electric Generation (MMcfd)	1-in-10 Year Peak Day Minimum Electric Generation, N-1 Contingency (MMcfd)
Core	808	808
Noncore, Non-Electric Generation	596	596
Noncore, Electric Generation	1,964	1,402
Total	3,368	2,806
Implied Curtailment at Minimum Generation	N/A	562

Source: Staff Analysis

This report includes a preliminary examination of the events of winter 2018-19. Last winter, electric generators were called upon for voluntary curtailments at a higher rate than the previous winter due to colder weather, especially in February. Inventory withdrawals of 42 Bcf were approximately twice the amount withdrawn in the prior two winters and included approximately 14 Bcf withdrawn from Aliso Canyon. The extensive cold weather sharply illustrated how rapidly storage inventories can dwindle and how rapidly storage withdrawal capacity declines.

Given that experience, looking beyond summer 2019 to the winter 2019-20 is important. Maximizing injections when demand is less than receipt point capacity is critical for protecting electric generation in the summer and gas reliability in the winter.

Measures to reduce reliability risks therefore remain necessary. Staff suggests continuing most of the current mitigation measures and exploring additional measures, including a) revising the operational flow order (OFO) penalties, b) revising the Withdrawal Protocol in the short-term, c) revising the OFO formula, d) helping customers use available pipeline capacity or injection capacity, e) conducting research into the gas cost incentive mechanism and pipeline utilization, f) continuing to implement a six-days-a-week/12 hours-a-day schedule to expedite critical transmission pipeline maintenance work, and g) optimizing the timing of discretionary maintenance to maximize injections while minimizing peak summer and winter season maintenance and associated reliability risks.

INTRODUCTION

This report is an assessment of electricity reliability in Southern California given the operating status of the Aliso Canyon gas storage facility. An overall cap on inventory of 34 billion cubic feet (Bcf) remains in place, and operations are still restricted by the Withdrawal Protocol to those required to maintain reliability. Challenges to reliability remain despite the increased inventory at Aliso Canyon because of significant pipeline outages on the SoCalGas system. The outages present in the SoCalGas system from summer 2018 and winter 2018-19 remain, and temporary capacity reductions for maintenance work appear likely through the remainder of the year. In addition, winter 2018-19 began with mild weather but the latter half of winter experienced significantly colder weather, which resulted in withdrawals of storage inventory twice the level of the prior two winters at 42 Bcf. Despite the higher starting inventory, the ending inventory on April 1 was 9 Bcf lower than winter 2017-18, which means more injections are needed for summer and winter reliability. April demand was lower than expected, allowing injections of about 7.8 Bcf during April.

The first section of this report recaps the findings from last summer's Aliso Canyon Technical Report and the events that occurred in both the gas and electricity markets. Second, the report summarizes supply, demand, and curtailments during summer 2018 and winter 2018-19. Third, the current operating status entering summer 2019 is discussed. Fourth, given the operating constraints on the gas system, this report assesses the risks to electricity reliability over the coming summer. Fifth, while this is a "summer" assessment, a gas balance exercise is performed through December 2019. This is an effort to assess how summer decisions might affect winter gas reliability and provide enough lead time for making decisions. Last, the assessment discusses potential new mitigation measures that have been or could be adopted to address the risk forecasted for this summer and the coming winter. Some of these mitigation measures are short-term solutions to address the risk.

Only 2,355 MMcfd to 2,785 MMcfd of pipeline capacity (depending on the timing of certain outages versus repairs) appear to be available this summer. These numbers are based on base case, pessimistic, and optimistic outlooks of pipeline outages and mitigations. Pipeline supply during June is lower in 2019 than in 2018 due to planned maintenance, but the supply beginning in July 2019 is similar to summer 2018. In the optimistic case, pipeline supply increases to 3,085 MMcfd in November, which is a slight increase compared to the optimistic projection of 2,930 MMcfd for summer 2018.

On the electricity side, this summer's analysis still assumes that all electric transmission lines are in service and able to import incremental energy that would otherwise be generated with natural gas inside the balancing authority area.[6] It also assumes that there is sufficient energy available from external suppliers at the quantity and duration necessary to meet these energy import requirements.

SoCalGas released its own technical assessment on April 2, 2019. The assessment group has engaged in discussions with SoCalGas about its analysis. SoCalGas' analysis presents more extreme bookend cases than the assessment group's cases, and the reality is more likely to be in-between their two cases. The gas balance cases show average demand days can be met without gas from Aliso Canyon. However, to meet a summer high sendout day, storage withdrawals, possibly including Aliso Canyon, will be required.

[6] A balancing authority is responsible for maintaining the electricity balance within its region. A balancing authority has several ways to maintain the balance of supply and demand, from turning on or of generators to importing or exporting excess electricity to or from their neighbors. (See http://www.tanc.us/chap6_picture.html.)

SUMMER LOOKBACK 2018

The SoCalGas system escaped significant curtailments during summer 2018, and no gas was withdrawn from Aliso Canyon.[7] The assessment group analyzed the past three summers and compared system conditions.

The original summer 2016 analysis pointed to demand of 3.2 Bcf per day or more, creating challenges for the gas system. Figure 1 plots gas system sendout for the past three summers. The figure demonstrates that demand was lower during most of summer 2018 than in summer 2016 or 2017. Counting the days with demand greater than 3.2 Bcf gives a sense of how frequently "stress" days occurred: Only six "stress" days occurred during summer 2016 compared to 10 "stress" days in summer 2017 and zero in summer 2018.[8] These counts appear in Table 3 and are depicted in Figure 2.

SoCalGas, the California ISO, and LADWP used a combination of weather notices, curtailment watches, customer advisories, demand response, restricted maintenance, and Flex Alert days to manage demand on challenging, high-demand days.[9] SoCalGas also used OFOs to incentivize shippers to balance their gas deliveries with their gas burn as needed. Prior technical assessments discussed at length how large imbalances create a need to use gas from storage.[10] The ability to issue OFOs was identified as a key mitigation measure in the original *Summer 2016 Technical Assessment* and remains a key tool to help balance the SoCalGas system while Aliso Canyon's use is restricted.

Even though summer 2018[11] was milder than the prior three summers, continued pipeline outages strained system operations. More low OFOs were called — 59 compared to 26 in summer 2017, as presented in Table 4. Mild weather in late August to September combined with the increased injection capacity made available when the CPUC increased the capacity on Aliso from 24 to 34 Bcf on July 2 enabled SoCalGas to increase injections and refill storage inventory by mid-September in preparation for winter.

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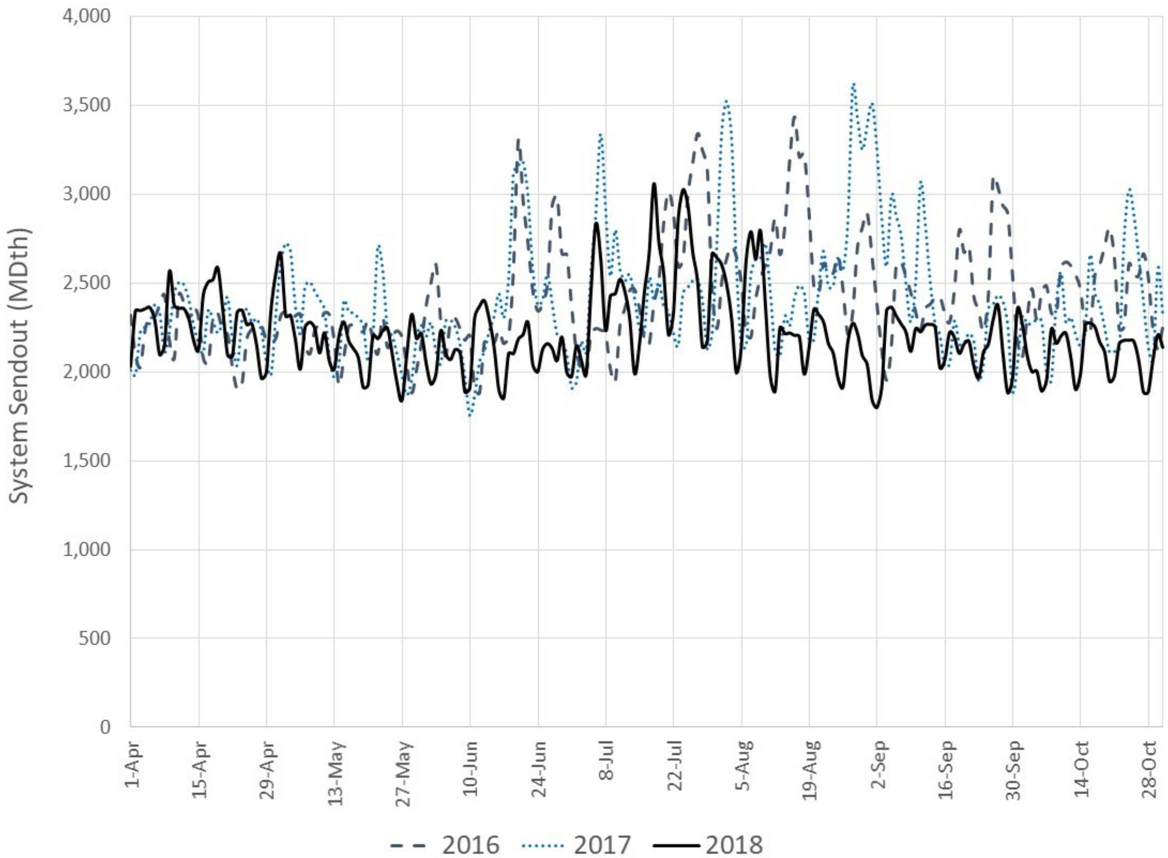
[7] However, it should be noted that there were significant gas price spikes that led to very high electricity prices, which in turn led to nearly a billion-dollar cost overrun for Southern California Edison.
[8] The frequency observed in these three years is different than the forecast frequency, or, the frequency at which they are expected to occur, on average, over a long period.
[9] The Energy Commission outlined use of these measures to avoid gas curtailments during the June 2017 heat wave in Appendix G of the *2017 Integrated Energy Policy Report.* Found at http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN223205_20180416T161056_Final_2017_Integrated_Energy_Policy_Report.pdf
[10] Prior technical assessments are available at
http://www.energy.ca.gov/2016_energypolicy/documents/index.html#04082016,
http://www.energy.ca.gov/2016_energypolicy/documents/index.html#08262016,
http://www.energy.ca.gov/2017_energypolicy/documents/#05222017,
https://www.energy.ca.gov/2018_energypolicy/documents/#05082018,
They can also be found at http://cpuc.ca.gov/alisoassessments/.
[11] During the period July 24 to July 26 2018, National Weather Service issued excessive heat warnings, but actual temperatures were as much as 10 degrees cooler than originally forecasted in some coastal regions thus reducing actual electric system demand relative to original forecasted levels that triggered low OFOs.

Figure 1: Daily Natural Gas Sendout (Demand) for Past Three Summers



Source: Staff Analysis

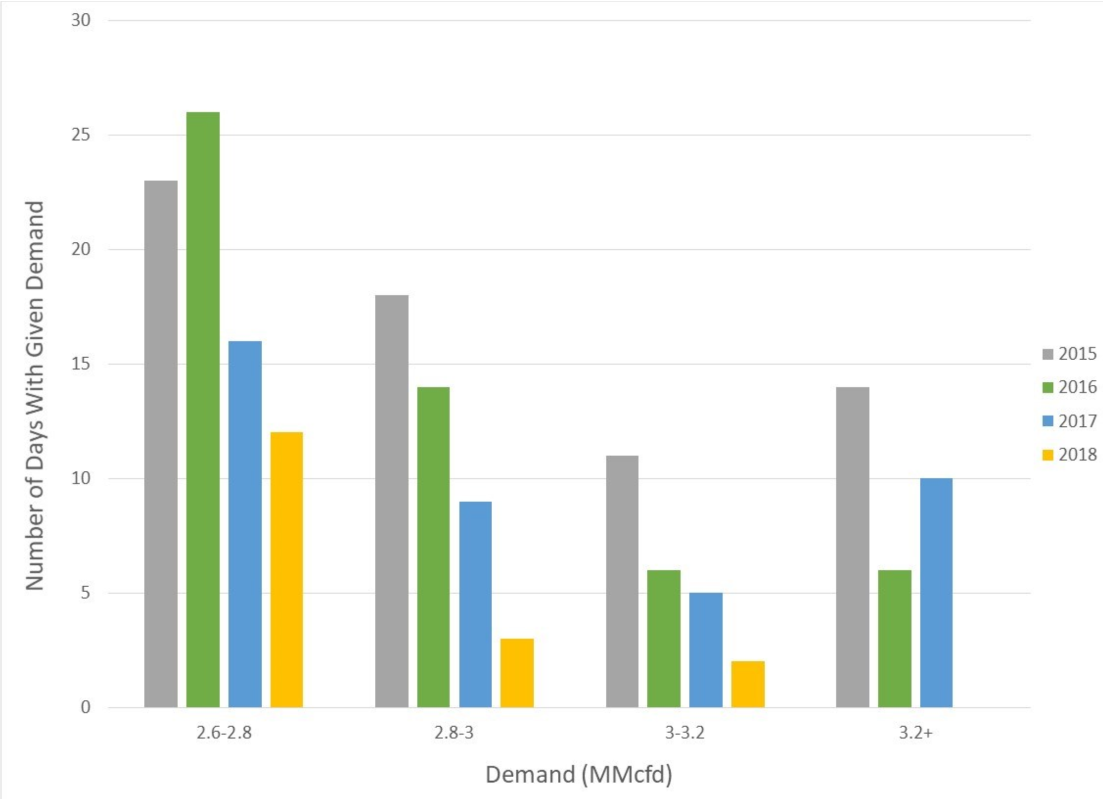
Table 3: General Distribution of Natural Gas Demand – Last Four Summers[12]

Bcf per Day	2.6-2.8	2.8-3	3-3.2	3.2+
Summer 2015	23	18	11	14
Summer 2016	26	14	6	6
Summer 2017	16	9	5	10
Summer 2018	12	3	2	0

Source: Staff Analysis

[12] SoCalGas average monthly summer demand with base hydro conditions is projected to be between 2.1 Bcf to 2.6 Bcf between June and September 2019. SoCalGas 1-in-10 year summer peak day forecast for summer 2019 is 3.4 Bcf. Demand of 3.2 Bcf or more has been identified as challenging conditions for the gas system.

Figure 2: Distribution of Daily Natural Gas Sendout (Demand) for Past Four Summers



Source: Staff Analysis

Table 4:
Use of Tools to Avoid Electricity Service Outages during Past Three Summers
Number of Days

	Weather Notice	Curtailment Watch	Flex Alert	Electric Generation Load Reduction Request (Curtailment)	Rule 23 Curtailment	Low Operational Flow Orders[13]	Delayed Work
Summer 2016		3	3			42	
Summer 2017	11	10	4			26	
Summer 2018	3	10	2	1		59	

Source: Staff Analysis

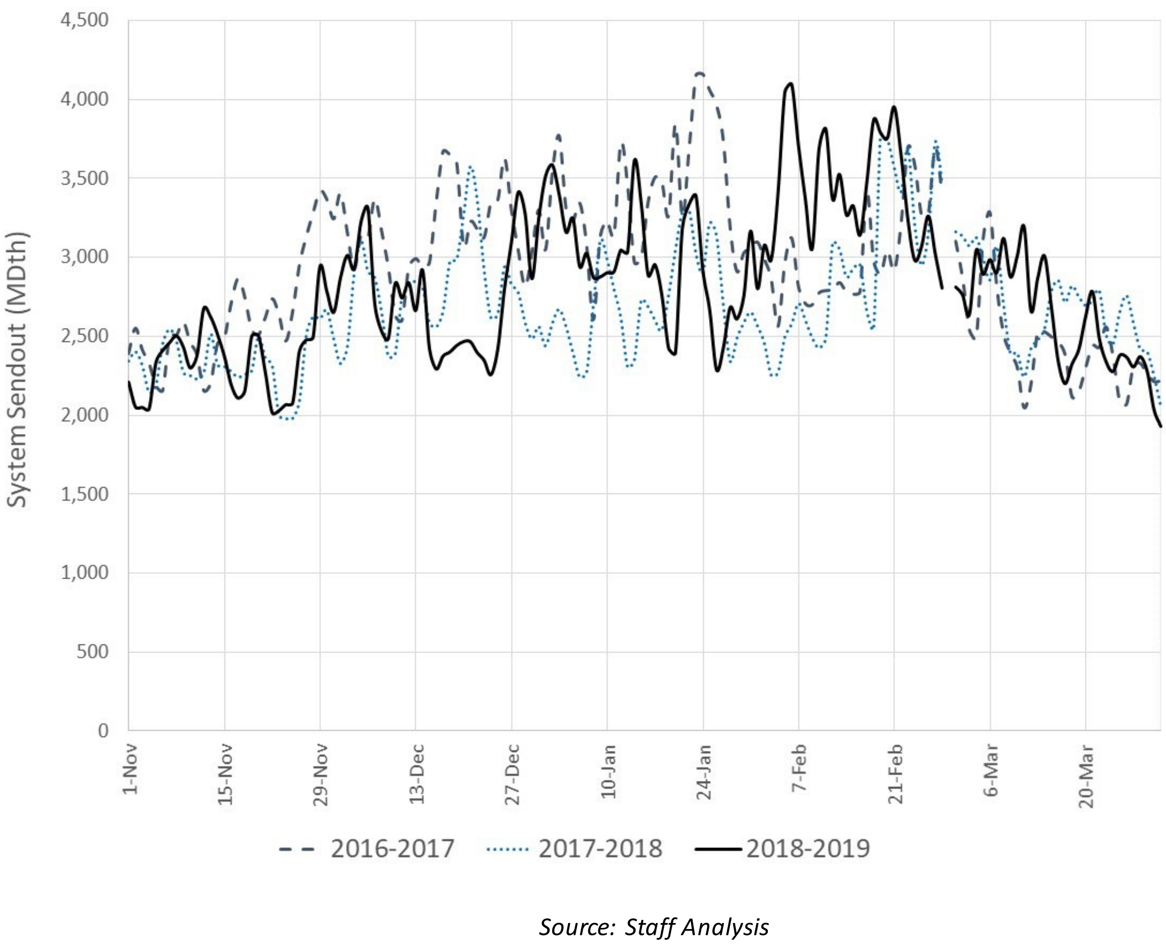
Note: the curtailments represent the number of days, not events, as one event may span multiple days.

[13] See https://scgenvoy.sempra.com/#nav=/Public/ViewExternalLowOFO.getLowOFOEvent%3Frand%3D77 for a detailed list of the OFO stage and balancing tolerance requirement.

WINTER LOOKBACK 2018-19

Similar to last summer's lookback, the assessment group analyzed last winter to provide an overview of system conditions and customer demand. Figure 3 plots gas system sendout for the past three winters. The figure demonstrates that while the first half of winter 2018-19 experienced relatively modest demand for natural gas, the latter half of the winter saw an increase in customer demand, which continued through February. The figure, however, does not paint a full picture of system occurrences since reported sendout loses value as a proxy for demand when a curtailment occurs. Sendout would have been higher without curtailments. Additionally, viewing daily data does not account for the possibility that there may have been specific hours where demand exceeded capacity, causing the need to use Aliso Canyon or curtail load. The other striking fact shown is that this past winter shows 32 days with demand greater than 3.2 Bcf, compared to winter 2017-18, which experienced 14 days with similar demand. These counts appear in Table 5 and are depicted in Figure 3.

Figure 3: Daily Natural Gas Sendout (Demand) for Past Three Winters



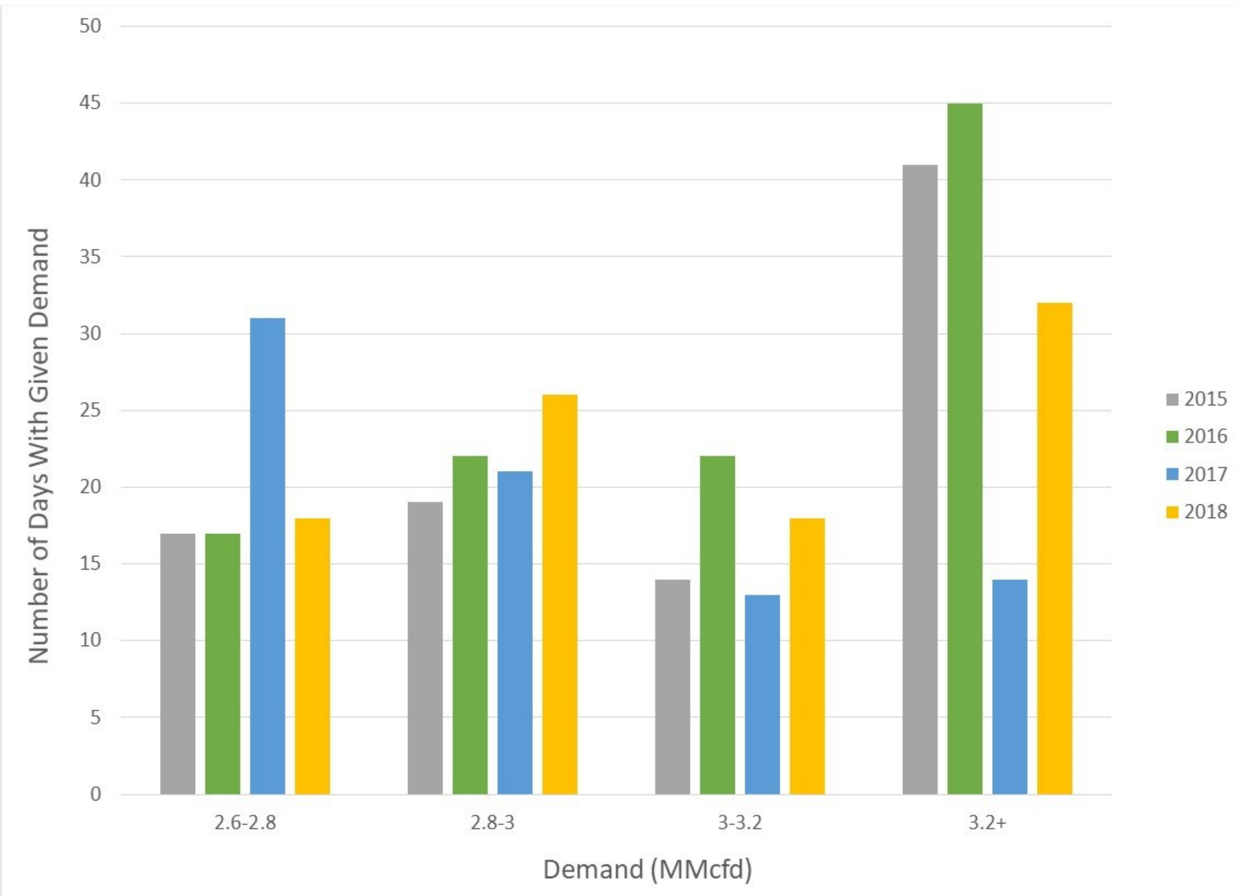
Source: Staff Analysis

Table 5: General Distribution of Natural Gas Demand - Last Four Winters

Bcf per Day	2.6-2.8	2.8-3	3-3.2	3.2+
Winter 2015	17	19	14	41
Winter 2016	17	22	22	45
Winter 2017	31	21	13	14
Winter 2018	18	26	18	32

Source: Staff Analysis

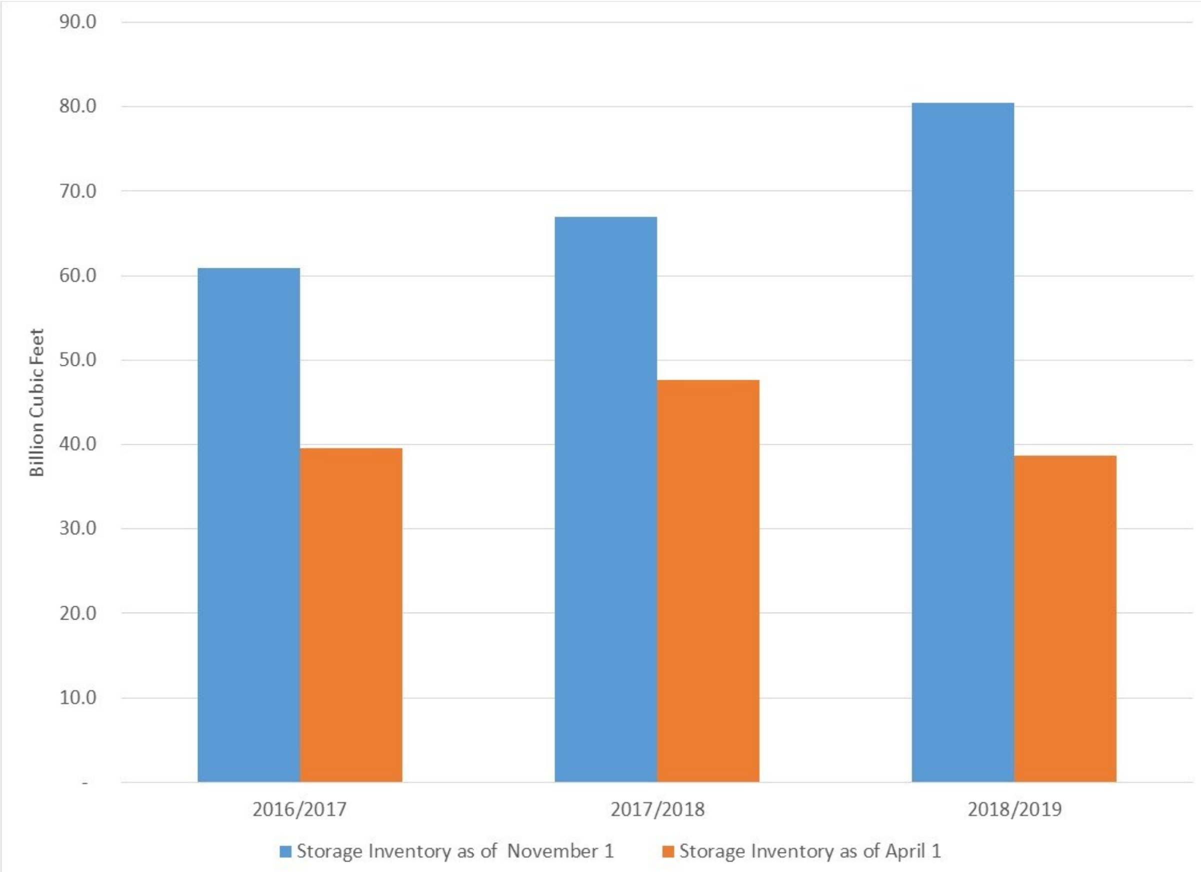
Figure 4: Distribution of Daily Natural Gas Sendout (Demand) for Past Four Winters



Source: Staff Analysis

This higher demand meant more storage withdrawals were needed, resulting in an April 1 inventory lower than last year, and winter season withdrawals that were double the prior two years. Figure 5 and Table 6 present the beginning and ending winter inventory levels and the cumulative withdrawal from storage. Prior analysis predicted that the continued pipeline outages could lead to greater reliance on storage, and that forecast was borne out: 42 Bcf was withdrawn from storage in winter 2018-19 compared to 19 to 21 Bcf during the prior two winters. As a result, more gas needs to be injected for summer and winter reliability.

Figure 5: Winter Season Inventory Levels



Source: Staff Analysis

Table 6: Winter Season Inventory Levels and Withdrawals

(Billion Cubic Feet)	2016-17	2017-18	2018-19
Starting Winter Storage Inventory November 1	60.9	67.0	80.5
Ending Winter Storage Inventory April 1	39.5	47.7	38.7
Total Net Withdrawal	21.4	19.3	41.8

Source: Data from SoCalGas Envoy

Table 7 highlights the tools used to maintain gas system reliability and avoid electricity service outages for winter 2018-19. Over the past winter, SoCalGas issued 14 Voluntary Curtailments covering 41 days, two system-wide curtailment watches covering 5 days, and two mandatory Rule 23[14] curtailments covering 5 days. This is the first time Rule 23 curtailments have been called since the gas leak at Aliso Canyon. SoCalGas also withdrew gas from Aliso Canyon to satisfy demand on some of those days. The number of days that voluntary load reduction to electric generation was called increased significantly this past winter. Requesting voluntary load reduction is required by the Withdrawal Protocol before SoCalGas can withdraw gas from Aliso Canyon. The CAISO did not participate in any voluntary load

[14] SoCalGas Tariff Rule 23 describes the continuity of service and interruption of delivery in the event of curtailments.

reductions because their gas generation was already at such a low level, whereas LADWP at times was able to curtail generation to assist SoCalGas. Withdrawals from Aliso Canyon were about 14 Bcf this past winter.

LADWP delayed its transmission line upgrade work again this winter. Work was stopped due to gas curtailments from February 5 to 25, and work was stopped again from March 5 to 8 due to heavy rain being forecasted and more gas curtailments. There were also various slowdowns due to weather throughout the winter. The stoppages and slowdowns both impacted the ability to complete the work prior to this summer.

Table 7:
Use of Tools to Avoid Electricity Service Outages during Past Three Winters
Number of Days

	Weather Notice	Curtailment Watch	Electric Generation Load Reduction Request (Voluntary Curtailment)	Rule 23 Curtailment	Low Operational Flow Orders	Delayed Work
Winter 2016-17	28	6	2		64	
Winter 2017 - 18	8	15	14		77	LADWP, California ISO[15] and SoCalGas
Winter 2018-19	3	5	41	5	80	LADWP

Source: Staff analysis.

Note: the curtailments represent the number of days, not events, as one event may span multiple days.

Similar to winter 2017-18, SoCalGas also used OFOs this past winter to incentivize shippers back to balance.

[15] LADWP's transmission system infrastructure improvement program requires season-long outages on their circuits over the next several winter seasons. These infrastructure improvements are necessary to mitigate existing transmission congestion in the LA basin. In the future, they will allow LADWP to import more renewable energy into the LA Basin from the north and from the east. LADWP's delay of work on their 138/230kV LA Basin transmission system, Valley-Rinaldi Lines 1 and 2 had scheduled to begin in November 2017 and continued into March. California ISO, during the February cold spell issued a notice restricting maintenance and postponed some planned transmission work.

The CPUC released the *Winter 2017-18 SoCalGas Conditions and Operations Report*[16] last December and plans to release an update for winter 2018-19 that will provide a more extensive look at last winter.

Natural Gas Prices

The brief lookback for last summer and winter included here identifies a number of challenges. In summer 2018 the number of OFOs increased, and in winter 2018-19 the number of calls for both voluntary and mandatory curtailments of electric generation increased. The operational challenges have been reflected in the increased volatility of natural gas prices at the SoCal Citygate. Figure 6 shows prices for natural gas transactions at the SoCal Citygate, which shows that price spikes have reached as high as $40/MMbtu last summer and $22/MMbtu this past winter, while prices at SoCal Border and PG&E Citygate were much less volatile. This is consistent with increased volatility at the SoCal Citygate since the rupture of Line 235-2 and the maintenance outage on Line 4000 that has been observed and noted in the Energy Commission's *2018 Integrated Energy Policy Report*.[17] The highest price increases occurred on the days that the system composite temperature was at its highest during summer and lowest during winter. In winter, the price increases tend to coincide with the dates when there were withdrawals from Aliso Canyon. In addition, price spikes tend to occur when additional maintenance reduced capacity on the system, whether planned or unplanned. The winter of 2016-17 had many more high demand days above 3.2 Bcf than either of the past two winters yet prices remained stable and only reached $4.05 in early January 2017 because the rupture of Line 235-2 occurred after the winter of 2016-17.

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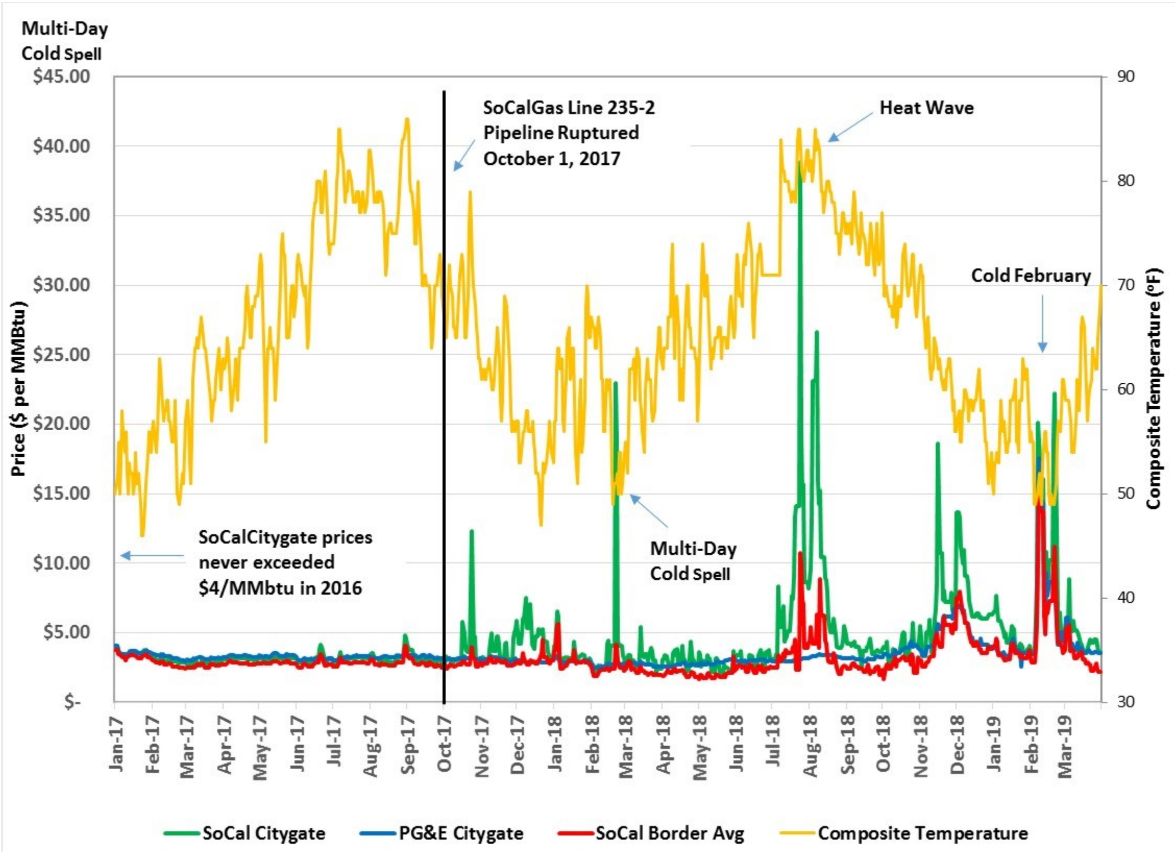
16 http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2018/Winter2017-2018LookbackReportCleanFinal_2018-12-06%20-%20v2.pdf

17 *2018 Integrated Energy Policy Report,* p. 206.

Figure 6: SoCal Citygate Prices during Heat Waves and Cold Spells



Source: Energy Commission Staff Analysis

CURRENT OPERATING STATUS OF THE SOCALGAS SYSTEM

SoCalGas may inject gas into the Aliso Canyon storage facility up to a 34 Bcf inventory limit specified by the CPUC in the "Section 715" report posted on July 2, 2018.[18] However, the Withdrawal Protocol put in place by the CPUC still prohibits withdrawals from Aliso Canyon except as an "asset of last resort." In addition to limitations on Aliso Canyon, continuing pipeline outages and planned maintenance have added to Southern California reliability challenges. These pipeline outages will continue through much of the summer.

In SoCalGas' Southern Zone, Line 2000 has been operating at reduced pressure since 2011 and will continue to do so until the line can be made safe to operate at higher pressures. In addition, capacity on Line 2000 is reduced by 30 MMcfd due to the expiration of a right-of-way through federal lands held in trust for the Morongo Band of Mission Indians. Shippers, such as natural gas customers, marketers, and agents, can address this capacity reduction, however, by using the North Baja and Gasoducto Baja Norte

[18] The latest Section 715 report can be found at http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/715Report_Summer2018_Final.pdf

pipelines to move gas from Ehrenberg, Arizona, to the Southern Zone receipt point at Otay Mesa.[19] On November 30, 2018, SoCalGas announced an agreement with the Morongo Band of Mission Indians for a 40-year right-of-way continuation for Lines 5000, 2001, and related distribution systems, which means no further loss of capacity is projected due to expiring rights-of-way.[20] In addition, planned maintenance on Line 2001 has reduced capacity at Ehrenberg in the Southern Zone by 350 MMcfd beginning March 15 through July 1, 2019, and should be complete by peak summer season.

SoCalGas' Northern Zone is still experiencing multiple issues. Line 3000 has continued to operate at a reduced pressure after repairs were completed in September 2018, increasing the Topock subzone from 0 MMcfd to 400 MMcfd. However, the return of Line 3000 did not lead to an incremental increase in the capacity of the Northern Zone as a whole. The Northern Zone is still limited to 870 MMcfd since Lines 235 and 4000 are still out or under restricted operations.[21] As of May 10, Line 235-2 is still out of service due to a rupture near the Newberry Compressor Station on October 1, 2017, and additional maintenance work due to a succession of new leaks. The return to service date is projected to be June 22, 2019. Line 4000 is operating at reduced pressure such that only an incremental 270 MMcfd is allowed into the system. Validation digs on Line 4000 will begin once Line 235-2 is back in-service. During the validation digs, Line 4000 will not be operational. If there are no immediate conditions found on Line 4000, SoCalGas expects the line to return to service at a reduced pressure on August 9, 2019. In the optimistic case, discussed later in this report, further testing and increasing operating pressure on Line 4000 are anticipated to increase capacity in November. The normal combined receipt point capacity of these Northern Zone pipelines is 1,590 MMcfd. Table 8 presents SoCalGas system pipeline capacity for summer 2019 base, pessimistic and optimistic cases. Pipeline capacity is projected to be similar to last summer at least for half, if not most of the summer.

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[19] Appendix A contains a system map so readers can identify the lines and locations discussed here.
[20] The right of way for Line 5000 and the Morongo gas distribution system expired on August 21, 2018, and the right of way for Line 2001 expires on March 22, 2020.
[21] See *critical notice* posted to Envoy on October 1, 2018 at https://scgenvoy.sempra.com/ebb/attachments/1538411998036_Line_3000_Update_100118.pdf .

Table 8:
SoCalGas System Pipeline Capacity

	Summer 2018				Summer 2019									
					Base			Pessimistic		Optimistic				2018 CA Gas Report
	As of April 10	Pessimistic	Optimistic	Combined (Pessimistic and Optimistic)	June 1- June 30	July 1- Aug 8	Aug 9	June 1- June 30	July 1+	June 1- June 30	July 1 - Aug 8	Aug 9 - Oct 31	Nov 1	
Receipt Point (MMcfd)														
North Needles	270[a]	0	270[a]	0	270	270	400	270	270	270	270	400	700	1,200
Topock*	0[b]	0	0[b]	0										
Kramer Junction	550	550	625[c]	625	600	600	550	600	600	600	600	550	550	
Ehrenberg	980	800	980	800	630	980	980	630	980	630	980	980	980	1,210[d]
Otay Mesa	30	150	230	230	30	30	30	30	30	30	30	30	30	
Wheeler Ridge	765	765	765	765	765	765	765	765	765	765	765	765	765	765
CA production	60	60	60	60	60	60	60	60	60	60	60	60	60	210[e]
TOTAL Supply	**2,655**	**2,325**	**2,930**	**2,480**	**2,355**	**2,705**	**2,785**	**2,355**	**2,705**	**2,355**	**2,705**	**2,785**	**3,085**	**3,385**

Source: Staff Analysis

[a] As long as Line 4000 is operating at reduced pressure, receipts at North Needles or Topock are limited to 270 MMcfd.

[b] The Line 3000 outage limits receipts at the Topock receipt point to zero.

[c] Firm deliveries at Kramer Junction are limited to 550 MMcfd; Kern River can deliver up to 700 MMcfd under certain system conditions.

[d] The nominal capacity of the Southern Zone is 1,210 MMcfd but achieving it requires 200 MMcfd be delivered via Otay Mesa. The Otay Mesa receipt point is rarely used and thus is excluded under "normal" conditions. The right-of-way expiration on Line 2000 means that 30 MMcfd must be delivered at Otay Mesa to keep the southern system total at 1,010 MMcfd.

[e] California production delivered to SoCalGas in recent years has run far below this nominal capacity value.

System Capacity

System capacity is projected to be in a similar range or a little lower in some cases than summer 2018 as repairs and remediation work continue through the summer, and uncertainty surrounds the timing of completion of repairs. Inventory at the non-Aliso fields is likely to be a little lower on July 1, 2019 than in summer 2018, and the corresponding withdrawal capability will be lower. Use of Aliso Canyon may be more likely this summer compared to last in which no withdrawals were made from Aliso Canyon. It depends on whether the July 1 inventory projection is achieved or not. SoCalGas has continued with its Storage Integrity Management Program (SIMP), which is a continuous well inspection program that includes the conversion of wells to tubing-only flow. The switch to tubing-only flow is expected to change the maximum withdrawal and injection capacity and the withdrawal and injection curves as each field undergoes this work. The maximum withdrawal capability, if the storage fields are full, is expected to be a little lower than last year due to SIMP.

Table 9 presents the projected system capacity ("supported demand") for summer 2019 and summer 2018 for comparison purposes. Three cases were developed that differ by the timing of the remediation work. Planned maintenance on Line 2001, which began on March 15, reduces the Ehrenberg receipt point by 350 MMcfd and should be complete by July 1. Thirty MMcfd is assumed at Otay Mesa. Line 235-2 is assumed to return to service in all cases, at which time Line 4000 is removed from service. Line 4000 is projected to return to service August 9 in the base case and is projected to remain out of service in the pessimistic case. In the optimistic case, further testing and increasing operating pressure are projected on Line 4000 increasing capacity estimated in November. The storage result of 680 MMcfd is derived from SoCalGas' Summer 2019 Technical Assessment[22] and is the mid-point between their best and worst cases and excludes Aliso Canyon. Any day that demand is greater than the assumed pipeline capacity requires using gas from storage. System capacity ranges between 3,035 MMcfd in June in all cases to 3,465 MMcfd mid-summer in the base case to 3,765 MMcfd in the optimistic case in November. The projected system capacity can be higher or lower, depending on available storage inventories. These projections compare last summer's results of 3,555 MMcfd to 3,425 MMcfd in the base and sensitivity cases, respectively and show this summer's results to be in a similar range.

[22] https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-09, TN# 227490.

Table 9: Assessment Group Base, Pessimistic and Optimistic Case Results

		SUMMER 2018		Summer 2019								
		Base Case	Sensitivity	Base			Pessimistic		Optimistic			
		DAY	DAY	June 1-June 30	July 1-Aug 8	Aug 9 +	June 1-June 30	July 1+	June 1-June 30	July 1 - Aug 8	Aug 9 - Oct 31	Nov 1 +
		MMcfd	MMcfd	MMcfd	MMcfd	MMcfd	MMcfd	MMcfd	MMcfd	MMcfd	MMcfd	MMcfd
Pipeline		**2,655**	**2,525**	**2,355**	**2,705**	**2,785**	**2,355**	**2,705**	**2,355**	**2,705**	**2,785**	**3,085**
	North Needles	270	0									
	Topock*	0	0	270	270	400	270	270	270	270	400	700
	Kramer Junction	550	700	600	600	550	600	600	600	600	550	550
	Ehrenberg	1010[1]	800	630	980	980	630	980	630	980	980	980
	Otay Mesa	0	200	30	30	30	30	30	30	30	30	30
	Wheeler Ridge	765	765	765	765	765	765	765	765	765	765	765
	CA production	60	60	60	60	60	60	60	60	60	60	60
Storage		**900**	**900**	**680[2]**	**680**	**680**	**680**	**680**	**680**	**680**	**680**	**680**
	Aliso Canyon	0	0	0	0	0	0	0	0	0	0	0
	Honor Rancho	380	380									
	La Goleta	220	220	680	680	680	680	680	680	680	680	680
	Playa del Rey	300	300									
Supported Demand		**3,555**	**3,425**	**3,035**	**3,385**	**3,465**	**3,035**	**3,385**	**3,035**	**3,385**	**3,465**	**3,765**

Source: Staff Analysis

[1] The assessment group defined its base case and requested that SoCalGas perform the hydraulic modeling before it knew that the Line 2000 right-of-way expiration would cause a reduction in capacity of 30 MMcfd. If the authors assume that this reduction reduces the supported demand in the hydraulic analysis on a 1:1 basis, the supported demand would not be the 3,555 MMcfd shown but instead would be 3,525 MMcfd. The assessment group has elected to show the 3,555 MMcfd because it is the factual result arising from the completed hydraulic runs using the assumptions given to SoCalGas and because sensitivity cases sufficiently capture alternate assumptions.
[2] The storage result of 680 MMcfd is derived from SoCalGas' Summer 2019 Technical Assessment and is the mid-point between their best and worst cases and excludes Aliso Canyon.

LADWP AND CALIFORNIA ISO JOINT ELECTRIC GENERATION IMPACT ANALYSIS AND RESULTS

The California ISO and LADWP, as the relevant electricity balancing authorities for generators in the Greater Los Angeles Area and Southern California, have updated their reliability analysis for the upcoming summer. This analysis determines how much natural gas the power plants must have to maintain system reliability under normal and unexpected contingency conditions.

The minimum gas burn by electricity generators calculated here is significantly lower than the electricity-generator gas burn under normal circumstances. It is the minimum that the balancing authorities must have to maintain electricity reliability. This calculation is not done to plan to curtail the generators to minimum but so that decision-makers know how much gas the power plants must have to avoid electricity service outages. Replacing the generation that would have occurred with this gas means the electric balancing authorities have moved generation to other, less desirable and more expensive facilities to reduce their gas requirement and the stress on the gas system. Such shifts increase the cost of electricity.

The more advance notice the balancing authorities have of such gas curtailments, the more they are able to reduce the impact on the electric system. Short notice of gas curtailments reduces the options available to secure additional import energy to replace the energy lost to curtailment. Because most replacement energy would have to be imported into the area, the ability to respond to short-notice gas curtailments will be limited by the electric transmission capacity and electric supply available outside the area at the time of the curtailment as well as the availability of local electric storage capacity.

Moving electric generators to minimum generation is not easy or desirable. It means shifting generation to less desirable and less economic sources and, depending on notice timing and available resources, places the California ISO and LADWP into one or more levels of Energy Emergency Alerts.[23] Moving to minimum generation also assumes that gas is available at the replacement plants, transmission and energy are available at the quantity and duration necessary to replace the generation, and no other outages occur among electric facilities. The assessment group, therefore, expects that SoCalGas would only curtail generators to minimum generation under emergency circumstances. Under CPUC rules, electric generators are considered noncore customers[24] in the SoCalGas/SDG&E service territories and are the first gas customers to be curtailed in times of system stress.[25]

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[23] Energy Emergency Alerts are defined at http://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf.

[24] Noncore service is provided to large industrial and commercial customers, hospitals, power plants, and oil refineries. Core service is provided to residential and small commercial customers and small industrial enterprises.

[25] SoCalGas Rule 23 can be found at https://www.socalgas.com/regulatory/tariffs/tm2/pdf/23.pdf. Rule 23 requires EG to curtail up to 40 percent of their load in the summer months and up to 60 per cent of their load during the winter months. Notably, moving the generators to minimum generation during the winter results in a curtailment of gas service that exceeds their obligation to cut 60 percent of their load under Rule 23 in the

The 2019 summer assessment focuses only on the electric reliability impact of gas constraints. There are also financial and environmental impacts of operating electric generation in inefficient and non-economic ways. This assessment does not attempt to quantify those impacts.

Summary of Electric Analysis and Findings

- The LADWP/California ISO joint 2019 power-flow study found that electric reliability can be met with 1.274 Bcfd of gas (including the qualifying facilities [QFs]).[26] This study assumes 1-in-10-year summer peak electric load conditions with the required minimum generation to maintain electric reliability under normal conditions and all transmission lines in service at the assigned emergency ratings.
- The electric system is expected to be able to maintain electric reliability for summer 2019 after July 1 without interruption in all scenarios assuming 85 percent or higher electric transmission import utilization and sufficient levels of gas storage supply are available.
- During peak summer load conditions and historic electric transmission utilization patterns, incremental gas-fired generation may be required to meet electric reliability. To the extent gas supply is insufficient to meet the increased gas demand, access to replacement energy may require emergency assistance from neighboring balancing authorities, and electric load shed in Southern California may be necessary.
- Although the electric system could operate with only minimum reliability must-run generation in gas constrained areas during the summer months, this is not commonly observed during a 1-in-10-year peak load day. Normal unconstrained, economic operation of the generation assets would require gas usage above the outcome of the reliability study. Using resources other than those that are most efficient and economic would result in increased energy dispatch costs.
- The summer reliability assessment focused on local transmission reliability including the contingency reserve requirement necessary to immediately meet the greater of the loss of the Most Severe Single Contingency (MSSC) or about 6 percent of the hourly peak load. The assessment also included replacement reserve capacity that will need to be sourced and procured after the first hour of a power system contingency. While the quantity and location of the generation commitment may vary depending on load level, system topology, fuel costs, and economics each day, historical experience and the summer 2019 seasonal assessment performed by the LADWP and California ISO show the need to have a minimum amount of generation commitment inside the Los Angeles, Orange County, and San Diego areas.

Assumptions

The key assumptions on the electricity side consist of a) the electricity load forecast, b) available electricity imports, and c) the impacts of an N-1 contingency, or outage event.

SoCalGas tariff. This is not true, however, for the summer, where the 40 percent curtailment under Rule 23 cannot be absorbed before reaching the minimum generation level.

[26] A *qualifying facility* is a qualifying cogeneration facility or qualifying small power production facility, as defined in the Code of Federal Regulations, Title 18, Part 292.

A. Electricity Load Forecast. The 1-in-10-year peak summer load electricity demand forecast for Southern California totals 35,895 megawatts (MW). It breaks down as follows:
   - SCE = 24,012 MW
   - SDG&E = 4,472 MW
   - LADWP = 7,411 MW[27]

B. Imports. The analysis assumes Southern California imports of 17,538 MW of electricity. This is higher than the 15,000 MW of summer imports achieved historically and is based on available transmission capacity. The actual level of imports achievable will depend on the availability of transmission and energy on the days and hours when needed.

C. Outages. The analysis takes into account planned transmission outages. For unplanned facility outages, the analysis reflects an N-1 contingency event assumed to reduce energy available by 1,100 MW for LADWP, 2,000 MW for the California ISO, and 2,873 MW for the combined LADWP and California ISO.[28]

Results

The results below are split into a minimum gas requirement under normal conditions versus a higher gas requirement should electricity system N-1 events occur.

Normal Electric Operating Conditions

The gas burn required to support electric generation in Southern California is projected to total 1,274 MMcfd. This is under normal conditions and includes gas required by QFs because the QFs account for about 10 percent of the gas burn requirement. The total requirement splits into 313 MMcfd for LADWP and 961 MMcfd for the California ISO. The two balancing authorities must be able to obtain at least this amount of gas in order to maintain electricity reliability.

To Recover From an N-1 Contingency

A contingency (outage) that would affect both LADWP and California ISO is the most severe N-1 electric outage that could occur in Southern California. Recovery from an N-1 electric contingency event increases the gas requirement because more gas-fired generation must be available and able to operate (meaning it must have access to fuel) to replace the lost electricity system component. This higher gas requirement lasts until the lost component can be restored. Both the California ISO and LADWP balancing authorities have to each carry their own operating reserve to meet their requirement to cover their largest contingency. However, the single event in Southern California could result in a larger loss of energy as compared to the individual event. This gas quantity from an outage is assumed to be available

[27] This includes LADWP plus the load of the utilities within its balancing area, consistent with prior technical assessments.

[28] N-1 is the loss of any generator, transmission line, transformer, or shunt device without a fault or single pole block on a high-voltage, direct-current (HVDC) transmission line. LADWP and the California ISO are independent balancing authorities. The N-1 event is different when determined for LADWP and the California ISO individually than when it is determined for the larger combined entity. The N-1 single event for the combined entity is not the sum of the individual events.

in the event of an electric system contingency to meet North American Electric Reliability Corporation (NERC) reliability requirements.

The most severe N-1 contingency is the loss of 2,000 MW for the California ISO and 1,100 MW for LADWP. The most severe single contingency for both the California ISO and LADWP combined is a different contingency that impacts both utilities and results in a combined loss of 2,837 MW. Replacing this lost energy means the combined California ISO and LADWP will require an additional 128 MMcfd of natural gas. Table 10 summarizes the minimum generation gas requirements, including the QFs.

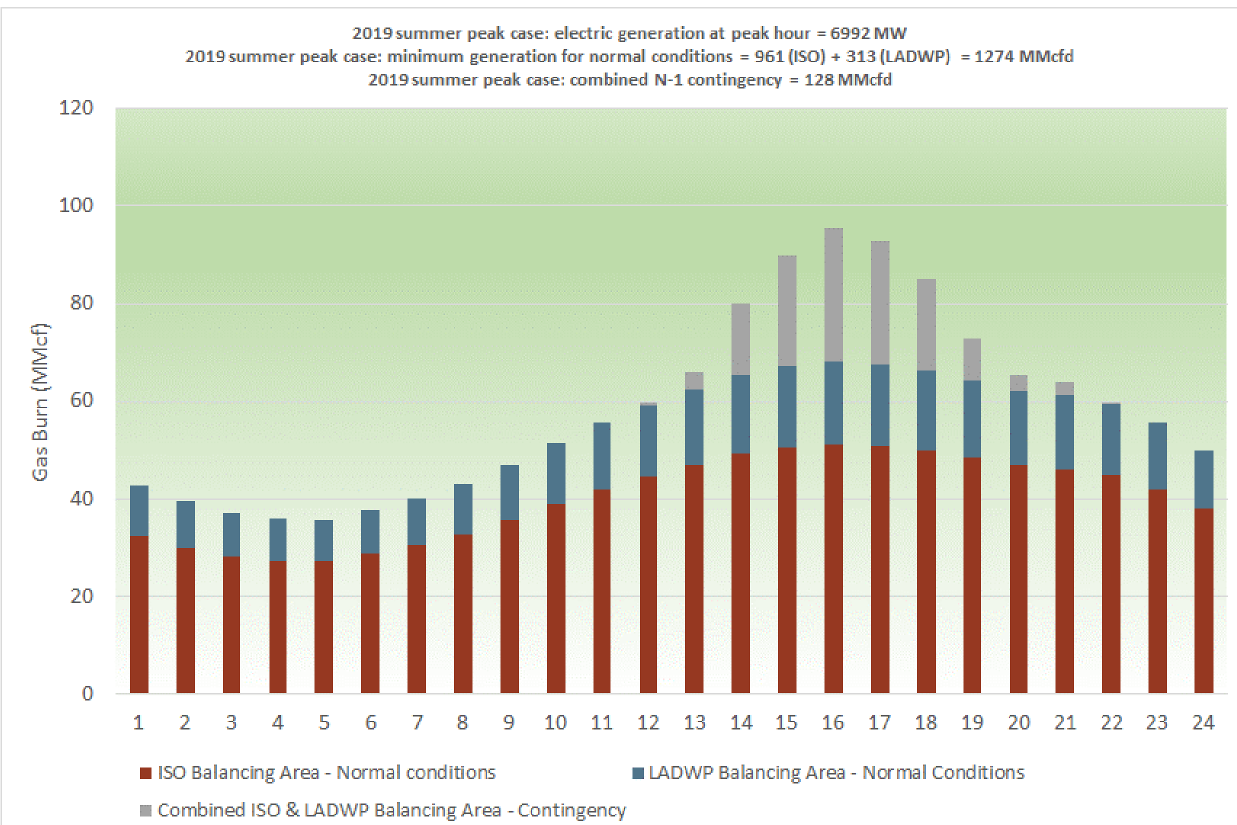
Table 10: Minimum Generation Gas Requirements Including QFs (MMcfd)

Condition	California ISO	LADWP	Total
Normal	961	313	1,274
N-1	128		1,274 + 128 = 1,402

Source: California ISO and LADWP

Figure 7 below shows the hourly minimum daily generation needed in the LADWP and the California ISO balancing authorities to meet normal conditions and to recover from a non-simultaneous contingency on a peak summer day. The generation need is translated into a gas requirement of 1,274 MMcfd and 1,402 MMcfd, including the QFs under normal and N-1 contingency conditions, respectively. Table 11 shows the peak hourly generation and gas burn by zone in the SoCalGas service area.

Figure 7: Summer Minimum Generation in the SoCalGas Service Area Including QFs



Source: California ISO

Table 11:
1-in-10 Peak Summer Case Including QFs at Minimum Generation: Peak Hour Energy (MW) and Gas Burn (MMcf per hour) for SoCalGas Area

Zone	Gen (MW)	Gas Burn (MMcfh)
Burbank	250.0	2.4
Coastal	142.2	1.4
EOM	0.0	0.0
Glendale	46.0	0.4
Inland	1,250.3	12.1
LA Basin	2,177.4	21.1
LADWP	1,426.0	14.0
Pasadena	100.0	1.0
Riverside	180.0	1.7
SDG&E	1,109.5	10.8
SJV	310.2	3.0
Grand Total	**6,991.6**	**68.0**

Source: California ISO

Table 12 summarizes the electric impact on the 2019 summer gas assessment. The combined California ISO and LADWP minimum generation gas burn, including the combined additional worst contingency for both balancing authorities, is 1,402 MMcfd.

Table 12:
Summary of Electric Impact on 2019 Summer Gas Assessment Including QFs

Row	Description	Formula	Gas Burn (MMcfd)
1	Actual ISO summer peak gas burn for recent years - September 1, 2017 (MMcfd)		1,649
2	Actual LADWP SoCalGas system gas burn for 2017 Summer Peak - August 31, 2017 (MMcfd)		379
3	Combined actual ISO and LADWP gas burns (MMcfd)	*row 1 + row 2*	2,028
4	ISO SoCalGas system gas burn with minimum generation - with all transmission lines in service and no outages (MMcfd)		961
5	LADWP balancing area gas burn with minimum generation — with all transmission lines in service and no outages (MMcfd)		313
6	Combined California ISO and LADWP minimum generation gas burn – with all transmission lines in service and no outages (MMcfd)	*row 4 +row 5*	1,274
7	ISO + LADWP combined SoCalGas system gas burn to cover additional worst contingency (MMcfd)		128
8	Combined ISO and LADWP minimum generation gas burn including the combined additional worst contingency from LADWP and ISO (MMcfd)	*row 6 + row 7*	1,402

Source: California ISO and LADWP

Difference Between 2018 Analysis and 2019 Analysis

In the 2018 summer assessment the minimum gas burn was 313 MMcfd for LADWP and 1,133 MMcfd for the California ISO under normal conditions, based on the assumption that all transmission lines were in service with import energy to meet load requirements. The assessment group anticipated that these very low gas burn requirements were sustainable only for a short period and that such a reduction would occur infrequently because they would be limited to the most extreme gas curtailment situations.

In the 2019 summer assessment, the minimum gas burn for LADWP remained the same at 313 MMcfd, and the California ISO's minimum burn was reduced to 961 MMcfd, which is 172 MMcfd lower than last summer's assessment. The power flow study assumed normal transmission system configuration with all lines in service at their emergency ratings. Thus, the gas burns provided in the analysis are the extreme minimums that the California ISO and LADWP could obtain with transmission lines utilized to their emergency ratings. As per NERC Standards, in this analysis the post-contingency flow can be operated at or below the emergency rating for a finite, pre-defined period. Following the contingency, the flow in the facilities should be operated below the emergency rating within no less than this pre-defined period of time. For this analysis, the pre-defined period is 30 minutes for the California ISO area and two hours for LADWP.

LADWP experienced an all-time peak on August 31, 2017, and used this load in the model and electric impact analysis for the 2019 Summer Technical Assessment. For the California ISO, the lower gas burn requirement can be attributed to the replacement of the Encina power plant with the more efficient Carlsbad plant, gas generation retirements in the SoCalGas service area, and transmission upgrades that have come online in the past year. These transmission upgrades allow more imports into the area, reducing the minimum in-area generation requirements and corresponding gas burn. The transmission upgrades are in Table 13.

Table 13:
In-Service Dates for California ISO Board Approved Transmission Projects

	Transmission Projects	**Participating Transmission Owner Service Territory**	**In-Service Dates**
1	Sycamore – Peñasquitos 230kV Line	SDG&E	In-Service 8/29/2018
2	San Onofre Synchronous Condensers (1x225 mega volt ampere reactive)	SCE	In-Service 10/16/2018

Source: Staff Analysis

Potential Gas Curtailment for Electric Generation

Determining the potential gas curtailment for electric generation is a two-step process. The first step is to calculate an adjusted summer peak day gas demand incorporating the minimum electric generation requirements. The next step is to compare the adjusted summer peak demand to the SoCalGas supportable demand or system sendout as shown in Table 9. The impact on electric generation, shown in Table 14, is based on the post N-1 contingency minimum generation combined gas burn of 1,402 MMcfd for the LADWP and California ISO, which is approximately 172 MMcfd less than the minimum combined gas burn in 2018. Minimum generation has continued to decline over the past couple of years.

The gas forecast as required by power plants on a 1-in-10 year peak day is 1,964 MMcfd. If the power plants must be taken to minimum generation, that demand would be reduced to 1,402 MMcfd, including the amount needed to support N-1 contingency conditions. The difference between those two figures is 562 MMcfd, which represents the largest cut gas-fired generators could withstand and still maintain electricity service reliability on a peak summer day, assuming 100 percent transmission utilization. Going to minimum generation is only achievable as long as the balancing authorities have the ability to import replacement electricity from external generation resources.

Table 14:
1-in-10 Year Summer Peak Day Demand Implied Curtailment at Forecast versus Minimum Electric Generation Levels

Summer Demand (MMcfd)	1-in-10 Year Peak Day Forecast[29]	1-in-10 Year Peak Day Minimum Electric Generation, N-1 Contingency,
Core	808	808
Noncore, Non-Electric Generation	596	596
Noncore, Electric Generation	1,964	1,402
Total	3,368	2,806
Implied Curtailment if Electric Generation Goes to Minimum Generation	N/A	562

Source: Staff Analysis

Table 15 identifies the pipeline supply available and the amount of gas needed from storage to meet the adjusted summer peak day demand shown in Table 14. In the assessment group's base case, 101 MMcfd of storage withdrawal is needed beginning July 1 if the power plants are cut to minimum generation levels. A similar result is found for the pessimistic case since the pipeline supply is the same. This amount is reduced to 21 MMcfd when Line 4000 is projected to return to service on August 9, 2019. As prior analysis has shown, if less flowing supply is available, more is needed from storage. Projected available withdrawal capacity of 680 MMcfd by July 1 from the non-Aliso Canyon fields indicates there should be sufficient storage withdrawals available to meet daily peak summer demand. However, meeting peak hourly withdrawals may be difficult even when there appears to be sufficient gas to meet daily demand. The difference between the projected storage available and storage needed or so-called "surplus" capacity could be used to allow generators to burn more than the minimum level. Any outage or change on the gas system that reduces gas system capacity below the 2,806 MMcfd minimum generation gas demand level will result in insufficient gas being available to keep the electricity system reliable on a summer peak day. Another interpretation is that there appears to be enough capacity that the generators should not need to be curtailed to minimum generation on a 1-in-10 peak day.

[29] The 1-in-10 year summer 2018 peak day forecast is based on Table 3 of SoCalGas' Summer 2019 Technical Assessment. The assessment group acknowledges the uncertainty surrounding the forecast and that a different forecast could have been used.

Table 15:
Shortfall or Surplus on a 1-in-10 Year Peak Day with Minimum Electric Generation and an N-1 Contingency, Assuming 100 Percent Gas and Electric Transmission Utilization (MMcfd)

	(MMcfd)	Assessment Group Base Case July 1-Aug 8	Assessment Group Base Case Aug 9 +
1	1-in-10 Year Customer Demand with Generation Curtailed to Minimum Levels	2,806	2,806
2	Pipeline Supply Available	2,705	2,785
3	Supply Needed from Storage (row 1- row 2)	101	21
4	Projected Storage Supply Available (Non-Aliso Canyon fields) (Table 9)	680	680
5	Projected Surplus/Deficit (row 4 – row 3)	579	659

Source: Staff Analysis

SoCalGas Rule 23 Summer Curtailment

Rule 23 curtailments refers to curtailments of all noncore customers according to the order specified in Rule 23. This is in contrast to "voluntary curtailments" by which Gas Control asks electric generators to reduce their gas use in order to reduce stress on the system and in doing so hopes to avoid mandatory curtailments under Rule 23. Table 16 summarizes the electric impact if there is an electric generation curtailment for gas using the SoCalGas Rule 23 curtailment order. If constrained gas system operations occur this summer and gas curtailments are needed, application of Rule 23 would cause up to 40 percent of electric generation load to be curtailed. If additional gas load must be shed, then SoCalGas goes to other noncore customers before curtailing more electric generation gas load. The actual 2017 peak day gas burn for California ISO and LADWP was about 1,649 MMcfd and 379 MMcfd respectively, as shown in Table 13. The peak load day used from 2017 was the highest summer load in recent years. If curtailment arises on the peak electric generation day, then the remaining gas left for electric generation after the maximum 40 percent electric generation curtailment is about 989 MMcfd and 227 MMcfd for California ISO and LADWP, respectively. However, the gas needed to meet the minimum generation for a 1-in-10 peak load with all the transmission lines in service and no outages is 961 MMcfd for the California ISO and 313 MMcfd for LADWP, which is higher for LADWP and lower for ISO than the gas left after the maximum Rule 23 curtailment. In addition, even more gas is needed to cover the additional worst contingency for the California ISO and LADWP combined. The results show a shortfall of 185 MMcfd including the gas needed to cover the worst contingency if a 40 percent Rule 23 curtailment went into effect on a peak day.

Table 16:
Summary of Electric Impact after Electric Generation Curtailment per SoCalGas Rule 23

Row	Description	Formula	ISO	LADWP
1	Gas burn from actual peak load day from recent years – 2017 (MMcfd)	*(row 1 and row 2 from table 12)*	1,649	379
2	Up to 40% EG curtailment in summer months; Remaining gas after EG curtailment based on 2017 peak day gas burn (MMcfd)	*(row1*0.6)*	989	227
3	Gas needed for 2019 1-in-10 peak load day with minimum generation with all transmission lines in service and no outages (MMcfd)	*(row 4 and row 5 of table 12)*	961	313
4	Shortfall of gas to meet the minimum generation for normal conditions after 40% EG curtailment (MMcfd)	*(row2 - row3)*	28	-86
5	Gas needed to cover the additional worst contingency for combined California ISO and LADWP balancing area (MMcfd)	*(row 7 of table 12)*	-128	
6	Total gas needed to cover the shortfall and the additional worst contingency for combined California ISO and LADWP balancing areas (MMcfd)	*(row 4, Columns 5 and 6 + row 5)*	-185	

Source: California ISO and LADWP

Ability to Resupply Energy Based on Electric Transmission Utilization

The power flow analysis simulated maximum possible imports into Southern California of 17,538 MW. However, the highest transfer observed is 15,500 MW, which is about 88 percent of the maximum simulated. Of this amount, 4,000 MW is expected to come from Northern California, 3,100 MW is expected to come from the Northwest, and the remainder is expected to come from Utah, Arizona, and Nevada.

If energy is already being imported and flowing prior to a gas curtailment, there will be limited capacity available to transport energy to absorb the curtailment.

Table 17 shows the impact on the electric system and the additional gas needed at different transmission import utilizations. The analysis reviews three cases:

1) Imports of 17,538 MW: 100 percent transmission capacity utilization as reviewed in the 1-in-10 summer peak day power flow analysis.
2) Imports of 15,784 MW: 90 percent transmission capacity utilization — about 2 percent higher than observed historical transmission utilization maximum.
3) Imports of 14,907 MW: 85percent transmission capacity utilization — about 3 percent lower than observed historical maximum transmission utilization.

The analysis starts with the forecasted 2019 1-in-10 year peak summer load for the Southern California region. It then sums up the maximum import capability; the maximum non-gas-fired generation capacity, such as hydro, solar and wind; and the minimum gas-fired generation needed to meet local reliability requirements. The sum of the generation must equal the load to maintain the electric power system balance. Table 17 shows the analysis of import energy into the Southern California region for three transmission utilization cases in Row 2. The combined LADWP and California ISO minimum gas-fired generation needed to meet reliability requirements is in Row 7. If the import utilization is insufficient, the required incremental gas generation is in Row 8. The incremental gas-fired generation required following a power system contingency event impacting Southern California is in Row 10. The incremental gas demand is Row 11, which represents the additional gas needed over the day relative to the 100 percent transmission utilization scenario. The results show that as transmission utilization decreases, the need for in-basin, gas-fired resources increases. The incremental gas demand in Row 11 is then compared to the gas system surplus in Table 15 after moving electric generation to minimum generation for the base case beginning July 1. Rows 13 show the net surplus for the base case. The results show sufficient gas system capacity for the base case with a surplus of 315 MMcfd under 90 percent electric transmission utilization and a surplus of 222 MMcfd in the 85 percent utilization.

Table 17: Summary of Assessment of Electric Impact-Based Transmission Utilization

Row	Description	Formula	2019 (1-in-10) peak summer case with minimum California ISO SoCalGas system and LADWP generation - 100% Import Utilization	2019 (1-in-10) peak summer case with minimum California ISO SoCalGas system and LADWP generation - 90% Import Utilization	2019 (1-in-10) peak summer case with minimum California ISO SoCalGas system and LADWP generation - 85% Import Utilization
1	California ISO and LADWP combined balancing areas: Load + Losses (MW)		35,895	35,895	35,895
2	Imports into Southern California from North and East (MW)		17,538	15,784	14,907
3	Total California ISO and LADWP combined generation (MW)	row1-row2	18,357	20,111	20,988
4	California ISO and LADWP combined non-gas generation (MW)		11,365	11,365	11,365

Row	Description	Formula	2019 (1-in-10) peak summer case with minimum California ISO SoCalGas system and LADWP generation - 100% Import Utilization	2019 (1-in-10) peak summer case with minimum California ISO SoCalGas system and LADWP generation - 90% Import Utilization	2019 (1-in-10) peak summer case with minimum California ISO SoCalGas system and LADWP generation - 85% Import Utilization
5	California ISO gas generation served by SoCalGas (MW)		5,270	6,603	7,270
6	LADWP gas generation served by SoCalGas (MW)		1,722	2,142	2,352
7	California ISO and LADWP combined gas generation (MW)	row5 + row6	6,992	8,745	9,622
8	Additional gas generation needed if import utilization is reduced from 100% (MW)		-	1,754	2,631
9	Additional generation needed following a contingency (MW)		2,837	2,837	2,837
10	Incremental additional supply needed from gas generation to cover the contingency (MW)	row8 +row9		4,591	5,468
11	Additional gas needed for 24 hours, if transmission utilization is reduced from 100% and to cover the additional contingency (MMcfd)[30]			264	357
12	Base case gas surplus, 1-in-10 year peak demand with generation curtailed to minimum levels (MMcfd)	Table 15, Base Case		579	579
13	Base case net surplus/shortfall to cover the specified scenario (MMcfd)	Row 12 - Row 11		315	222[31]

Source: Staff Analysis

GAS BALANCE ANALYSIS

The Energy Commission prepared gas balances in order to provide an assessment independent of SoCalGas and to test additional sensitivity cases with alternate assumptions. As explained in prior technical assessments, a gas balance is not a projection of future occurrences. Rather, it is a tool that demonstrates what may happen if the demand, supply, and storage assumptions shown come to fruition. A gas balance allows us to assess the difference, or margin, between capacity (or supply) versus demand to determine in general whether capacity is sufficient to meet demand. It also allows us to simulate the impact to storage inventory from monthly storage injections and withdrawals. Also, it is important to recognize that the demand forecasts used are for average daily consumption for each month, and do not account for peak demand. There will be days in the summer that will have higher or lower demand than the averages shown. The balance should demonstrate a positive deliverability margin, meaning more capacity than demand, so that the system retains capacity to deal with unplanned outages or days with demand higher than forecasted. A gas balance exercise does not simulate operations hydraulically to determine constraints or assess hourly operations.

Conditions for the upcoming summer remain largely similar to last summer's operational constraints and are far more constrained than those seen for summer 2017 or summer 2016 are. In addition, the April 1 storage inventory is lower than last summer, which means more gas needs to be injected for both summer and winter reliability. Table 8 (above) shows the firm receipt point capacity of SoCalGas' pipeline system from the *2018 California Gas Report* (with partial outages) totaling 3,385 MMcfd. The current pipeline outages and planned maintenance reduce this to 2,355 MMcfd through June; capacity is projected to increase in July to 2,705 MMcfd and again to 2,785 MMcfd beginning in September. SoCalGas has stated that this increase is projected to occur August 9, but to keep the gas balance simple, the increase is assumed to occur September 1. There is a chance that Line 235-2 may not return to service as planned or that Line 4000 remediation work will take longer than anticipated such that the Northern Zone supply remains the same through the end of the year, which is reflected in the pessimistic case. There is also a chance that further remediation of Line 4000 will increase capacity in November, which is reflected in the optimistic case. Staff differed from SoCalGas' analysis in that none of the staff balances automatically discount supply to 85 to 95 percent of pipeline capacity. Staff assumes full use of available capacity and believes the discounting confuses the issue of behavior with true available capacity and creates the appearance of a greater need for gas from Aliso Canyon. However, analyses of past pipeline utilization shows that maximum pipeline utilization is rare. For example, winter 2018-19 experienced an average capacity utilization of 94 percent during peak demand hours.

The gas balance also considers the updated regulations from the Division of Oil, Gas, and Geothermal Resources (DOGGR) for California underground gas storage projects effective October 1, 2018.[32] Part of these new regulations require semiannual field shut-ins for testing and inventory verification, conducted

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[30] 357 MMcfd of gas is equivalent to 36,950 MWh of energy for 24 hours, which is about 1,540 MW of generation needed per hour for 24 hours from a gas plant(s) with a 10,000 Btu/kWh heat rate. Gas Burn (MMcfd) = (10,000/1,030,000)*Mwh.

[31] Note: The calculated surplus of 222 MMcfd is based on pipeline supply of 2705 MMcfd expected after July 1, 2019. If 1-in-10 load conditions occurred prior to July 1, 2019 a deficit of 128 MMCfd would occur at 85% import utilization. Under such conditions withdrawal from Aliso may be necessary to maintain electric system reliability.

[32] https://www.conservation.ca.gov/dog/Documents/GasStorage/Final-Text-of-Regulations-UGS.pdf.

at the point of seasonally high and low inventories. The regulations prohibit injections and withdrawals during the field shut-in tests. If a withdrawal is made during testing, the test must be started again. To implement these new regulations, SoCalGas scheduled each field to be shut-in for verification during the shoulder season in April/May and again in September/October/November. The length of the shut-in depends on the field's size and characteristics. In general, the larger fields, Honor Rancho and Aliso Canyon, have a longer shut-in period than the smaller ones. For example, Honor Rancho's low inventory shut-in period took place from April 1 to April 22. Removing Honor Rancho from service for three weeks during the spring and two weeks in the fall (projected fall maintenance) will result in less opportunity for injections. This will make refilling inventory for summer and winter reliability more challenging this year. Furthermore, given that the non-Aliso fields will be shut-in twice a year, consideration should be given to whether the current Aliso Canyon inventory maximum is adequate to ensure sufficient system injection capacity to fill storage for summer and winter reliability.[33]

The tables below run through December to take account of impacts that summer decisions may have on reliability for next winter. They calculate the deliverability margin of capacity versus demand under 1-in-2-year normal temperature conditions.[34] Demand for all cases comes from the gas demand forecast published in the *2018 California Gas Report* prepared by California's gas utilities with some oversight support from staff at the CPUC and Energy Commission. Each of the gas balance cases applies the storage inventory reported on Envoy on April 21, 2018. It also applies the Aliso Canyon inventory reported by SoCalGas in daily logs submitted to the CPUC.[35]

The main difference between the cases is the duration of the outages and the return-to-service dates of the pipelines. The demand for the month of April was adjusted to reflect actual conditions as of April 21 because demand was much lower than average during the first three weeks of the month. Lower demand allowed gas to be injected into storage rather than withdrawn to meet daily consumption. This lower demand enabled SoCalGas to inject about 7.8 Bcf during April, which puts the April 30 ending inventory a little over 4 Bcf lower than last year.

The Base Case (Table 18) assumes current pipeline capacity of 2,355 MMcfd in June and an increase to 2,785 MMcfd by September. The Base Case does not allow for a reserve margin until October. Storage achieves 57 Bcf by July 1, which is about 5 Bcf lower than last year, and is full by November 1. November deliverability reserve margin is 12 percent, which is in an ideal range.[36] The standard margin desired in a gas balance is 15 percent; using a 0 percent margin means that these numbers are likely optimistic and leave no room for unforeseen events. There is no flexibility for warmer (or colder) days or additional problems. Serving normal demand in December requires withdrawing gas from storage, which results in a decline from 81 Bcf to 72 Bcf of inventory across all four storage fields.

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[33] The vast majority of injection capacity on the SoCalGas system is at the Aliso Canyon field. When Aliso Canyon reaches its maximum, the limited injection capacity at the other fields may lead to difficulties injecting gas into storage, especially when any of the non-Aliso fields is shut-in.

[34] This assessment does not include cases for the 1-in-10 year "cold and dry" forecast. The normal temperature case analyses are enough to demonstrate the risk to reliability and the "deliverability balance" shows the margin available to cover increased demand.

[35] January 6, 2016 data request from the CPUC to SoCalGas to provide daily logs of storage inventory by field.

[36] Using a positive margin would be the first step to protect electric generation should a summer peak day for electricity occur. During months with injections, SoCalGas could also back down injections on higher demand days but were that to occur consistently, the winter inventory target could not be achieved.

The Pessimistic Case (Table 19) assumes that either Line 235-2 does not return to service as planned or that Line 4000 remediation work takes longer than anticipated such that the Northern Zone supply remains the same through the end of the year. In this scenario, the Northern Zone is limited to deliveries of 870 MMcfd. These assumptions result in 2,355 MMcfd of deliveries into the system, with an increase to 2,705 MMcfd in July.

Assuming average demand, the Pessimistic Case achieves 57 Bcf in inventory by July 1 and allows storage refill to occur by the end of October. The pessimistic case does not allow for a reserve margin until November. Meeting normal December demand would require withdrawing 381 MMcfd from storage. As a result, the total inventory in all four storage fields at the end of December is 69 Bcf. Again, a 0 percent margin means that these numbers leave no room for demand that is expected on individual days to be higher than the monthly average shown and leave no room for unforeseen events. This means that actual events could be worse than shown in this pessimistic case.

In the Optimistic Case (Table 20), Line 4000 increases capacity around November. The projections in the optimistic case are the same as the Base Case until November when capacity on the Northern Zone increases to 1,250 MMcfd and total supply increases to 3,085 MMcfd. Positive reserve margins are achieved in October and November, and there would be just enough flowing supply to meet normal December demand, leaving December inventory intact. This case clearly demonstrates that getting the pipelines back in service achieves the most positive outlook for next winter.

Table 18: Gas Balance Base Case

SoCalGas Monthly Gas Balance										
SoCalGas Monthly Gas Balance NORMAL WEATHER										
CGR Demand (MMcfd)		**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Core		N/A	761	655	614	618	636	718	1,058	1,494
Noncore including EG		N/A	1,053	1,174	1,430	1,595	1,548	1,263	1,012	1,059
Wholesale & International		N/A	350	326	360	412	409	362	384	494
Co. Use and LUAF		N/A	28	28	31	34	33	30	31	39
Subtotal Demand		2,247[1]	2,192	2,183	2,435	2,659	2,626	2,373	2,485	3,086
Storage Injection (Other Three Fields)[2]		55	163	172	220	46	125	162	0	0
Storage Injection (Aliso)		0	0	0	50	0	34	150	0	0
Storage Injection Total		*55*	*163*	*172*	*270*	*46*	*159*	*312*	*0*	*0*
System Total Throughput		2,302	2,355	2,355	2,705	2,705	2,785	2,685	2,485	3,086
Supply (MMcfd)										
California Line 85 Zone		60	60	60	60	60	60	60	60	60
Wheeler Ridge Zone		765	765	765	765	765	765	765	765	765
Blythe (Ehrenberg) into Southern Zone		630	630	630	980	980	980	980	980	980
Otay Mesa into Southern Zone		30	30	30	30	30	30	30	30	30
Kramer Junction into Northern Zone		600	600	600	600	600	550	550	550	550
North Needles into Northern Zone		270	270	270	270	270	400	400	400	400
Topock into Northern Zone		0	0	0	0	0	0	0	0	0
Sub Total Pipeline Receipts		2,355	2,355	2,355	2,705	2,705	2,785	2,785	2,785	2,785
Storage Withdrawal (Other Three Fields)[2]		0	0	0	0	0	0	0	0	301
Storage Withdrawal (Aliso)		0	0	0	0	0	0	0	0	0
Total Supply		2,355	2,355	2,355	2,705	2,705	2,785	2,785	2,785	3,086
DELIVERABILITY BALANCE (MMcfd)	Inv. As of	53	0	0	0	0	0	100	300	0
Reserve Margin	04/21	2%	0%	0%	0%	0%	0%	4%	12%	0%
OTF Month-End Storage Inventory (Bcf)	19	20	25	30	37	39	42	47	47	38
Aliso Month-End Storage Inventory (Bcf)	27	27	27	27	28	28	29	34	34	34
Total Storage Inventory	45	47	52	57	65	67	72	81	81	72

Source: Energy Commission Staff Analysis

Note: A ideal reserve margin target of 15% was unable to be achieved while maximizing injections to rebuild storage inventory.

Note 1: April demand was adjusted for 21 days of actual demand and 9 days of projections based on the California Gas Report.

Note 2:The storage injection and withdrawals represent average net injection or withdrawals for the month.

Table 19: Gas Balance Pessimistic Case

SoCalGas Monthly Gas Balance										
SoCalGas Monthly Gas Balance NORMAL WEATHER										
CGR Demand (MMcfd)		**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Core		N/A	761	655	614	618	636	718	1,058	1,494
Noncore including EG		N/A	1,053	1,174	1,430	1,595	1,548	1,263	1,012	1,059
Wholesale & International		N/A	350	326	360	412	409	362	384	494
Co. Use and LUAF		N/A	28	28	31	34	33	30	31	39
Subtotal Demand		2,247[1]	2,192	2,183	2,435	2,659	2,626	2,373	2,485	3,086
Storage Injection (Other Three Fields)[2]		55	163	172	220	46	79	162	45	0
Storage Injection (Aliso)		0	0	0	50	0	0	170	0	0
Storage Injection Total		*55*	*163*	*172*	*270*	*46*	*79*	*332*	*45*	*0*
System Total Throughput		2,302	2,355	2,355	2,705	2,705	2,705	2,705	2,530	3,086
Supply (MMcfd)										
California Line 85 Zone		60	60	60	60	60	60	60	60	60
Wheeler Ridge Zone		765	765	765	765	765	765	765	765	765
Blythe (Ehrenberg) into Southern Zone		630	630	630	980	980	980	980	980	980
Otay Mesa into Southern Zone		30	30	30	30	30	30	30	30	30
Kramer Junction into Northern Zone		600	600	600	600	600	600	600	600	600
North Needles into Northern Zone		270	270	270	270	270	270	270	270	270
Topock into Northern Zone		0	0	0	0	0	0	0	0	0
Sub Total Pipeline Receipts		2,355	2,355	2,355	2,705	2,705	2,705	2,705	2,705	2,705
Storage Withdrawal (Other Three Fields)[2]		0	0	0	0	0	0	0	0	381
Storage Withdrawal (Aliso)		0	0	0	0	0	0	0	0	0
Total Supply		2,355	2,355	2,355	2,705	2,705	2,705	2,705	2,705	3,086
DELIVERABILITY BALANCE (MMcfd)	Inv. As of	53	0	0	0	0	0	0	175	0
Reserve Margin	04/21	2%	0%	0%	0%	0%	0%	0%	7%	0%
OTF Month-End Storage Inventory (Bcf)	19	20	25	30	37	39	41	46	47	36
Aliso Month-End Storage Inventory (Bcf)	27	27	27	27	28	28	28	34	34	34
Total Storage Inventory	45	47	52	57	65	67	69	80	81	69

Source: Energy Commission Staff Analysis

Note: A ideal reserve margin target of 15% was unable to be achieved while maximizing injections to rebuild storage inventory.

Note 1: April demand was adjusted for 21 days of actual demand and 9 days of projections based on the California Gas Report.

Note 2:The storage injection and withdrawals represent average net injection or withdrawals for the month.

Table 20: Gas Balance Optimistic Case

SoCalGas Monthly Gas Balance

SoCalGas Monthly Gas Balance NORMAL WEATHER										
CGR Demand (MMcfd)		**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Core		N/A	761	655	614	618	636	718	1,058	1,494
Noncore including EG		N/A	1,053	1,174	1,430	1,595	1,548	1,263	1,012	1,059
Wholesale & International		N/A	350	326	360	412	409	362	384	494
Co. Use and LUAF		N/A	28	28	31	34	33	30	31	39
Subtotal Demand		2,247[1]	2,192	2,183	2,435	2,659	2,626	2,373	2,485	3,086
Storage Injection (Other Three Fields)[2]		55	163	172	220	46	125	162	0	0
Storage Injection (Aliso)		0	0	0	50	0	34	150	0	0
Storage Injection Total		*55*	*163*	*172*	*270*	*46*	*159*	*312*	*0*	*0*
System Total Throughput		2,302	2,355	2,355	2,705	2,705	2,785	2,685	2,485	3,086
Supply (MMcfd)										
California Line 85 Zone		60	60	60	60	60	60	60	60	60
Wheeler Ridge Zone		765	765	765	765	765	765	765	765	765
Blythe (Ehrenberg) into Southern Zone		630	630	630	980	980	980	980	980	980
Otay Mesa into Southern Zone		30	30	30	30	30	30	30	30	30
Kramer Junction into Northern Zone		600	600	600	600	600	550	550	550	550
North Needles into Northern Zone		270	270	270	270	270	400	400	700	700
Topock into Northern Zone		0	0	0	0	0	0	0	0	0
Sub Total Pipeline Receipts		2,355	2,355	2,355	2,705	2,705	2,785	2,785	3,085	3,085
Storage Withdrawal (Other Three Fields)[2]		0	0	0	0	0	0	0	0	1
Storage Withdrawal (Aliso)		0	0	0	0	0	0	0	0	0
Total Supply		2,355	2,355	2,355	2,705	2,705	2,785	2,785	3,085	3,086
DELIVERABILITY BALANCE (MMcfd)	Inv. As of	53	0	0	0	0	0	100	600	0
Reserve Margin	04/21	2%	0%	0%	0%	0%	0%	4%	24%	0%
OTF Month-End Storage Inventory (Bcf)	19	20	25	30	37	39	42	47	47	47
Aliso Month-End Storage Inventory (Bcf)	27	27	27	27	28	28	29	34	34	34
Total Storage Inventory	45	47	52	57	65	67	72	81	81	81

Source: Energy Commission Staff Analysis

Note: A ideal reserve margin target of 15% was unable to be achieved while maximizing injections to rebuild storage inventory.

Note 1: April demand was adjusted for 21 days of actual demand and 9 days of projections based on the California Gas Report.

Note 2:The storage injection and withdrawals represent average net injection or withdrawals for the month.

SoCalGas performed and included in its 2019 Summer Technical Assessment[37] what it calls a "mass balance." It provides additional variation on the staff cases described above but assumes more extreme conditions, creating bookend cases. The SoCalGas mass balance differs in that it converts the demand forecast from daily to monthly values, discounts pipeline capacity by an additional 5 to 15 percent, and runs only through October 2019. While staff's gas balances also use different assumptions about how much gas is available at Kramer Junction and Otay Mesa, SoCalGas' worst case assumes loss of both Line 235-2 and Line 4000 whereas staff's gas balance assumes at least one of those lines in service. SoCalGas' best case assumes a more optimistic timeline for return to service of Line 4000.

MITIGATION MEASURES

With this fourth summer of capacity reductions on the natural gas system in Southern California causing continued risk of interruptions in electricity service, the assessment group recommends continuing most of the mitigation measures implemented previously and adding several others. Some of the mitigation measures proposed have not been implemented, such as contracting for liquefied natural gas (LNG). Energy Commission staff and its consultants believe procuring LNG could have helped avoid some of the price spikes seen during this past year and implementing this measure should be considered.[38] To the extent that any of the existing measures in place now involve tariff approvals by either the CPUC or the Federal Energy Regulatory Commission that expire and need to be extended, the assessment group's mitigation monitoring effort will identify and remind the appropriate parties to seek extension. This section does not address implementation but instead describes the new mitigation measures the assessment group recommends exploring.

First, the analysis shows that frequent use of OFOs during the past summer and winter, and that SoCalGas will likely continue to rely on them as long as the outages continue. The technical assessment group recommends that the CPUC continue its efforts to revise the OFO penalty structure to minimize the economic impact of OFOs. The CPUC has an open proceeding to address the modification of OFO noncompliance charges in order to provide some cost relief to end-use electric generation customers and a proposed decision has been issued for the voting meeting of May 30, 2019.[39] If the CPUC adopts changes to the current OFO penalty structure as a result of the open proceeding, CPUC staff may study the impacts of these changes before summer 2020 to determine their effectiveness. Additionally, the CPUC has an open proceeding on core customer balancing requirements. Currently, core customers balance their burn to a forecast rather than to actual usage.[40] If balancing requirements are modified to more closely reflect actual operating conditions, the results may reduce the number of OFOs issued and lead to less system stress.

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[37]http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/SoCalGas%20Summer%202019%20Technical%20Assessment%20040219.pdf

[38] EIA reported that liquefied natural gas imports played a key role in reducing price spikes in New England this winter, https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2019/04_18/ .

[39] The Petition for Modification of OFO Noncompliance Charges is the subject of proceedings A.14-06-021/14-12-017. The proposed decision is available at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M285/K085/285085989.PDF.

[40] Core balancing is the subject of proceeding A.17-10-002.

Second, the assessment group recommends that the CPUC consider revising the Withdrawal Protocol in the short-term, which may increase system reliability and could decrease the number of OFOs and curtailment of electric generation customers. The use of Aliso Canyon in the long-term will be determined in the CPUC Aliso Canyon OII. Anytime that demand exceeds pipeline supplies, withdrawals from storage are needed. Compounding the issue is the rate at which gas travels — approximately 30 miles per hour — making proximity an important factor in assessing response time to peak demand. There may be days when intraday demand increases at such a rapid rate that gas flowing in from transmission pipelines is not able to reach the Los Angeles basin in time to meet the rise in demand. Thus, the need to use underground gas storage continues to be a reality to meet hourly demands. The Aliso Canyon Withdrawal Protocol, revised by the CPUC on November 2, 2017, may affect SoCalGas' ability to respond to peak demand increases when the combined non-Aliso storage fields and flowing pipeline supplies are not able to meet peak demand in time. The CPUC should consider revising the Withdrawal Protocol, which may increase system reliability, and could decrease the number of OFOs and curtailment of electric generation customers. A possible revision could be to allow the OFO level to trigger Aliso Canyon withdrawals.

Third, SoCalGas recently made a slight modification to the OFO formula to help reduce the number of low OFOs. The settling parties to the Second Daily Balancing Settlement Agreement should work with SoCalGas to verify whether there are other refinements that could be made to the OFO formula to decrease the incidence of OFOs.

Fourth, continue to consider ways to make injection capacity accessible to customers with injection rights as was done in 2018 through the Second Injection Enhancement Plan.[41]

Fifth, the assessment group suggests that the CPUC research whether there is an interaction between the Gas Cost Incentive Mechanism (GCIM) and pipeline utilization. If such a link is established, the CPUC should review the GCIM mechanism to determine what modifications would be appropriate.

Sixth, SoCalGas should continue to work six days a week and 12 hours per day to complete maintenance work on critical transmission pipelines as the company agreed to do in response to a February request to expedite that work by the CPUC's Energy Division and Safety and Enforcement Division. The CPUC remains concerned about the management of the pipeline outages and has committed to continue monitoring the situation closely to ensure that all appropriate measures are brought to bear to reduce the outages.

Seventh, SoCalGas should optimize the timing of discretionary maintenance to maximize injections while still minimizing summer and winter peak season maintenance. SoCalGas should provide additional information on its maintenance outlook and schedule, including timing and whether the maintenance is required by a regulating agency, such as the CPUC, DOGGR, or the Pipeline and Hazardous Materials Safety Administration.

CONCLUSION

The SoCalGas system continues to operate at less than full capacity due to significant pipeline outages and continuing restrictions on use of the Aliso Canyon gas storage facility. About twice the amount of

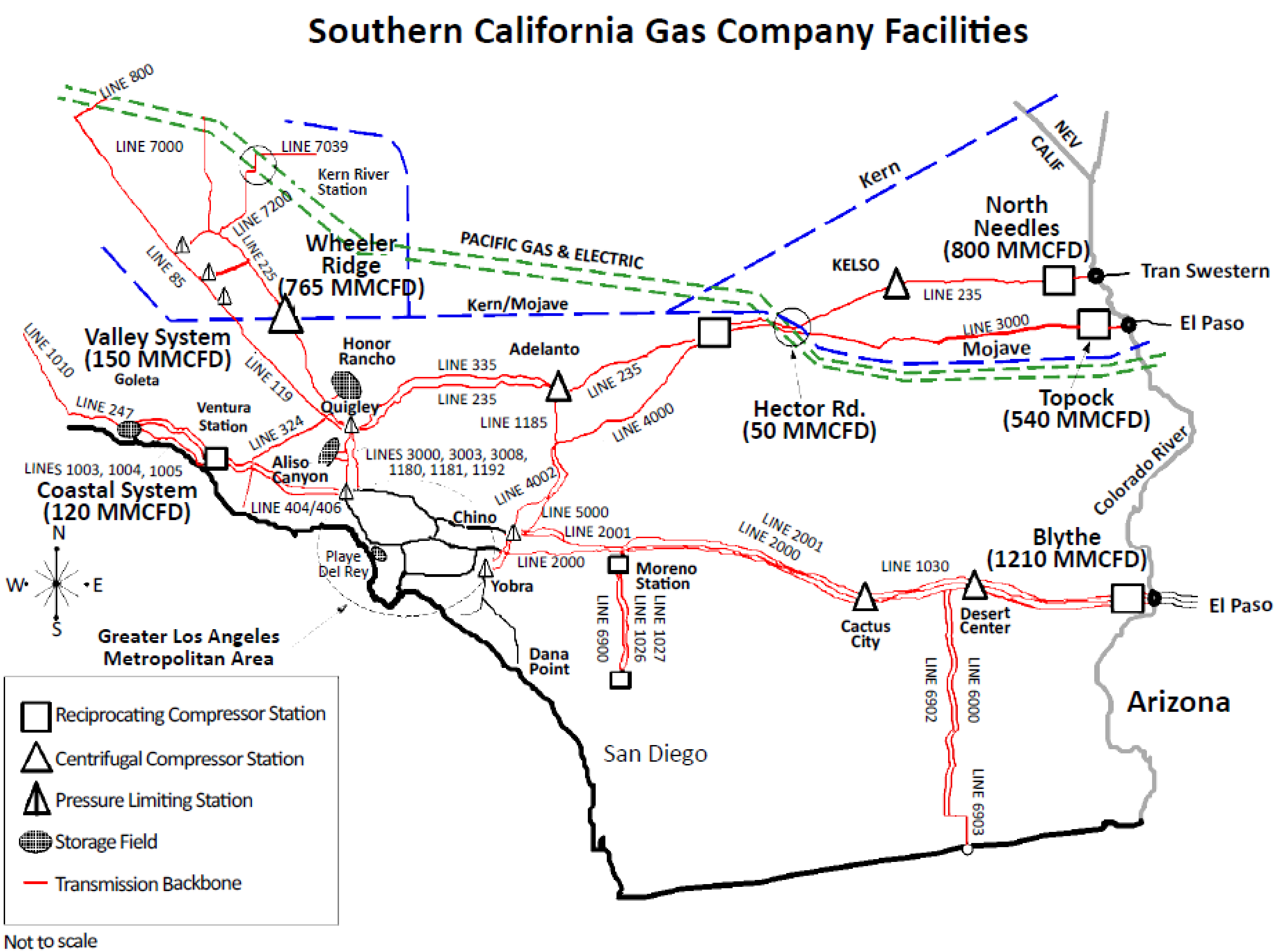
[41] Advice Letter 5275-A-G: https://www.socalgas.com/regulatory/tariffs/tm2/pdf/5275-A.pdf.

storage inventory was used this past winter than the prior two winters, which means more natural gas needs to be injected to refill storage inventory to protect electric generation for summer and winter reliability. Achieving a sufficient July 1, 2019 storage inventory level and corresponding withdrawal capacity will require maximizing injections when demand is less than receipt point capacity. More than 7.5 Bcf was injected into storage in April, which puts SoCalGas on track to achieve this goal. The reduction in pipeline capacity and uncertain July 1, 2019 inventory creates a threat to electric reliability this summer, which could result in customers being asked to reduce their electricity use. This threat is partially offset by the lower minimum generation requirement for electric reliability.

The outlook for winter 2019-20 is dependent on when the pipelines returned to service and whether restrictions on Aliso Canyon are eased. If the pipeline outages continue, it may be difficult for SoCalGas to fill storage to a level sufficient to ensure energy reliability throughout the winter. The biannual storage field shut-ins required by the new DOGGR rules decrease the system's flexibility and make injection more difficult. Revising the Withdrawal Protocol may increase flexibility. If the pipelines remain out of service, filling storage will depend on the weather and demand. The potential for the pipeline outages to end means that the situation may finally be getting better.

Last winter, SoCalGas made more calls for voluntary curtailments of electric generation, and more gas was used from Aliso Canyon than in any other prior season since the Aliso Canyon gas leak occurred in late 2015. The continuous stretch of cold weather this past winter provided a sharp illustration of how fast storage inventories can dwindle and how quickly storage withdrawal capacity can decline. Given the experience of winter 2018-19, the CPUC should consider whether the current Aliso Canyon capacity is adequate to ensure summer and winter reliability. To avoid service interruptions this summer and to mitigate potential price spikes, the CPUC should require SoCalGas to fix their pipelines as soon as possible and consistent with the current schedules. Beyond that, it appears the electric system is at least situated slightly better to absorb the gas limitations this year due to some of the electric system transmission upgrades and hydro conditions.

APPENDIX A: SoCalGas System Map



Source: February 24, 2004 Phase I Proposal by SoCalGas and SDG&E in R. 04-01-025-

APPENDIX B: Updated List of Mitigation Measures Including All Measures Proposed Since April 2016

Prudent Aliso Canyon Use	1. Make at Least 15 Bcf Stored At Aliso Canyon Available for Electric System Reliability, Including the Summer
	2. Efficiently Complete the Required Safety Review at Aliso Canyon to Allow Safe Use of the Field
Tariff Changes	3. Implement Tighter Gas Balancing Rules
	4. Modify Operational Flow Order Rule
	5. Call Operational Flow Orders Sooner in Gas Day
	6. Provide Market Information to Generators Before Cycle 1 Gas Scheduling
	7. Consider California ISO market changes that increase gas-electric coordination
Operational Coordination	8. Increase Electric and Gas Operational Coordination
	9. Establish More Specific Gas Allocation among Electric Generators In Advance of Curtailment
	10. Determine Whether the Reliability Benefits of Deferring Any Gas Maintenance Tasks Outweigh the Safety Risks
LADWP Operational Flexibility	11. Update Physical Gas Hedging Practice
	12. Update Economic Dispatch Practice
	13. Update Block Energy and Capacity Sales Practice
	14. Explore Dual Fuel Capability
Reduce Natural Gas and Electricity Use	15. Ask customers to Reduce Natural Gas and Electricity Energy Consumption
	16. Expand Gas and Electric Efficiency (EE) Programs Targeted at Low Income Customers
	17. Expand Demand Response (DR) Programs
	18. Reprioritize Existing Energy Efficiency Towards Projects with Potential to Impact Usage
	19. Reprioritize Solar Thermal Program Spending to Fund Projects for Summer and by end of 2017 and add/accelerate solar PV programs
	20. Accelerate Electricity Storage
Market Monitoring	21. Protect California Ratepayers
Gas-targeted Programs to Further Reduce Usage	22. Develop and Deploy Gas Demand Response (DR) Program
	23. Develop and Deploy Gas Cold Weather Messaging
Winter Operations Changes	24. Create Advance Gas Burn Operating Ceiling for Electric Generation
	25. Keep the Tighter Balancing Rules
	26. Modify Core Balancing Rules
Use of Gas from Aliso Canyon	27. Update the Aliso Canyon Withdrawal Protocol and Gas Allocation Process

Reduce Gas Maintenance Downtime	28. Submit Reports Describing Progress on Restoring Pipeline Service
Increase Gas Supply	29. Identify and solicit additional gas supply sources including more CA Natural Gas Production
	30. Prepare to Buy LNG
Refineries	31. Monitor Natural Gas Use at Refineries and Gasoline Prices
Added Summer 2017	32. Increase Gas Inventories at the Other SoCalGas Storage Facilities
Added Winter 2017-18	33. Delay LADWP's Transmission Upgrade Work
	34. Use More Gas From Aliso Than Last Winter
	35. Turn Thermostats Down and Deploy More Smart Thermostats
	36. Use Electricity Generators' Generation Shift to Help Reduce Gas Demand/Preserve Inventory
	37. Update Section 715 Report's Aliso Canyon Inventory Target for New Circumstances
	38. Bring LNG to Otay Mesa if Cannot Acquire Pipeline Capacity
	39. Monitor and Communicate Constantly, Including to Public
Added Summer 2018	40. Buy LNG to assure that up to 230 MMcfd can reach Otay Mesa on a firm basis
	~~41.~~ Coordinate with gas customers to ensure they are prepared to respond to both High and Low operational flow orders
	42. Give the SoCalGas operational hub permission to buy gas to fill the receipt points to full capacity when capacity would otherwise go unused
	43. Expedite any pending transmission upgrades that would further reduce the EG minimum generation requirement
	44. Monitor the "Energy Infrastructure Demand Response Act of 2018" to ensure California is considered as a region for any DOE-sponsored demand response pilot programs.
New Summer 2019	45. Revise OFO penalty structure.
	46. Revise the Aliso Canyon Withdrawal Protocol.
	47. Revise the OFO formula.
	48. Help injectors use available pipeline capacity or injection capacity
	49. Research any interaction between the gas cost incentive mechanism and pipeline utilization.
	50. Maximize maintenance work on the weekends to expedite the schedule of repairs and when demand is lower and price spikes are less likely to occur.
	51. Optimize the timing of discretionary maintenance to maximize injections.

Source: Staff Analysis

APPENDIX C: Glossary of Terms

Bcf	Billion cubic feet	Unit of measurement for gas storage inventory.
EG	Electric Generation	Power plant generation.
1-in-10 year	1-in-10 year	The term 1-in-10-year represents the warmest condition expected to occur once in 10 years and is used for planning capacity needed to serve noncore customers.
DOGGR	Division of Oil, Gas, and Geothermal Resources	California Government Agency that prioritizes protecting the public and the environment in its oversight of the oil, natural gas, and geothermal industries in California.
DR	Demand Response	Programs that ask customers to conserve energy.
EE	Energy Efficiency	Programs that lead to lower consumption of energy.
GCIM	Gas Cost Incentive Mechanism	The gas cost incentive mechanisms established by the California Public Utilities Commission encourage utilities to procure natural gas at or below a benchmark price. The benchmark price is based on a basket of monthly and some daily natural gas price indices.
High OFO	High operational flow order	High operational flow order is called by the gas company when there is too much supply to meet demand.
LNG	Liquified Natural Gas	LNG could be delivered to the Energía Costa Azul in Baja, California.
Low OFO	Low operational flow order	Low operational flow order is called by the gas company when there is insufficient supply to meet demand
MMcfd	Million cubic feet per day	Unit of measurement for gas demand.
MSSC	Most Severe Single Contingency	The balancing contingency (outage) event, due to a single contingency, that would result in the greatest loss (measured in MW) of resource output. It affects the amount of reserves that an electric balancing authority must carry for reliability.
MW	Megawatts	A unit of power equal to one million watts, used as a measure of the output of a generating station.

NERC	North American Electric Reliability Corporation	NERC is a not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.
OFO	Operational flow order	Operating tool used by SoCalGas to its customers to bring supply and demand into balance.
QFs	Qualifying facilities	The Public Utility Regulatory Policies Act of 1978 (PURPA) established a new class of generating facilities, known as qualifying facilities, which receive special rate and regulatory treatment. These can be qualifying small power production facilities and qualifying cogeneration facilities.
Rule 23 Curtailment	Rule 23 Continuity of Service and Interruption of Delivery	Rule 23 curtailments refers to curtailments of all noncore customers according to the order specified in SoCalGas Tariff Rule 23.
Sendout	Sendout	Total gas produced, purchased (including exchange gas receipts), or net withdrawn from underground storage within a specified time interval, measured at the point(s) of production and/or purchase, and/or withdrawal, adjusted for changes in local storage quantity. It comprises gas sales, exchange, deliveries, gas used by company, and unaccounted for gas. Expressed in various units such as therms, Btu, cubic feet, etc.
Shut-in	Shut-in	Shut-in refers to stopping production at a natural gas well or all wells at a natural gas storage field.
SIMP	Storage Integrity Manageme nt Program	SoCalGas' SIMP is a program that identifies and mitigates potential storage well safety and/or integrity issues.
SoCalGas	Southern California Gas Company	Natural Gas Company operating within California, subsidiary of Sempra Utilities.
Voluntary Curtailment	Voluntary curtailment	SoCal Gas Control asks electric generators to reduce their gas use in order to reduce stress on the system and in doing so hopes to avoid mandatory curtailments under Rule 23.

Withdrawal Protocol	Aliso Canyon Withdrawal Protocol	Conditions under which SoCalGas can withdraw natural gas from the Aliso Canyon Natural Gas Storage Facility. The Aliso Canyon Withdrawal Protocol and subsequent clarifying documents can be found here: http://cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/11.2Protocol%20PUBLIC%20UTILITIES%20COMMISSION.PDF