Summer 2021 Southern California Gas Reliability Assessment

BY CALIFORNIA PUBLIC UTILITIES COMMISSION STAFF

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Executive Summary

The Southern California Gas Company's (SoCalGas) gas system approaches summer with sufficient supplies to meet peak summer demand. Pipeline and storage capacity combined can provide 3,725 million cubic feet per day (MMcfd) of natural gas, which is more than enough to meet last summer's peak demand day of 3,175 MMcfd. Although this daily demand can be met without using the Aliso Canyon natural gas storage facility (Aliso Canyon), all four storage facilities including Aliso Canyon may be used on such a day to help meet hourly demand.

The SoCalGas system currently has healthy storage inventories and sufficient pipelines in service despite planned maintenance on Line 4000. The combined non-Aliso storage fields—Honor Rancho, Playa del Rey, and La Goleta—were 70 percent full as of March 31, and the Aliso Canyon storage field was at 50 percent of its maximum allowable capacity of 34 billion cubic feet (Bcf). Together these levels represent nearly three times the March month-end minimum of 15.3 Bcf specified by SoCalGas.

The Line 4000 transmission pipeline, which has been operating at reduced pressure, will be taken out of service for remediation from May 1 through September 30. This will reduce firm capacity in the Northern Zone from 990 MMcfd to approximately 870 MMcfd during the remediation period. The Northern Zone has a nominal capacity of 1,590 MMcfd but has been operating at reduced capacity due to safety concerns on Lines 4000, 3000, and 235.[1]

Despite the planned maintenance of Line 4000, staff's gas balance analyses (see Appendix) show that the non-Aliso fields could be filled by June, and Aliso Canyon could be filled by July in a scenario that assumes the average amount of hydroelectric power will be available. All four fields are slightly drawn down by October due to withdrawals in August and September. In a dry hydro scenario, which assumes that there is a drought and a below-average amount of hydroelectric power is available, the non-Aliso fields become full by June, and Aliso Canyon does not reach its maximum allowable capacity of 34 Bcf. Withdrawals are needed in July, August, and September. All four storage fields are more significantly drawn down by October. SoCalGas will need to ramp up injections in October and November; however, under the dry hydro scenario, it may not be able to fill up its storage fields near maximum levels before the winter season.

SoCalGas released its own Summer 2021 Technical Assessment on April 1, 2021, which presented analyses for best-case and worst-case supply scenarios.[2] Under its best-case supply scenario, SoCalGas does not expect to have enough supply to fill storage by the end of the summer season. In the worst-case scenario, SoCalGas assumes it will not have enough pipeline capacity to meet forecasted demand. Under this worst-case scenario, SoCalGas assumes that additional transmission

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[1] Reducing pipeline pressure is an established way to decrease the likelihood that a pipeline will leak or rupture. However, reducing the pressure decreases the amount of gas it can carry.

[2] SoCalGas Summer 2021 Technical Assessment: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2021/2021%20SUMMER%20TECHNICAL%20ASSESSMENT%201April21%20[Final].pdf

pipelines will be out of service, presumably due to potential "third-party damages and safety-related conditions."[3]

In addition to the gas balance analyses, staff undertook an analysis of a forecasted summer peak demand day. Staff also assessed the gas demand levels during the rolling electric blackouts of August 2020. The gas demand on those days—including electric generation, core, and other demand—was above forecasted summer peak. Tables 1 and 2 below summarize the results of the summer peak day demand analysis, which is further explained later in the report. Staff concluded that the gas system can meet that level of daily demand this summer, even with Line 4000 out of service. Staff did not perform hydraulic modeling to examine whether hourly demand could also be met using only the non-Aliso fields. Depending on hourly demand and gas deliveries on a peak day, Condition 1 of the Withdrawal Protocol could be triggered, and Aliso Canyon might be used.

Table 1: Summer High Demand Day with Line 4000 Out of Service and Aliso Canyon Unavailable (MMcfd)

Summer Peak Day Demand	Projected System Capacity	Surplus/ Shortfall
3,160	3,235	265

Table 2 Summer High Demand Day with Line 4000 Out of Service and Aliso Canyon Available (MMcfd)

Summer Peak Day Demand	Projected System Capacity	Surplus/ Shortfall
3,160	3,725	755

This report is authored by CPUC staff and was shared with staff at the California Energy Commission, the California Independent System Operator, and the Los Angeles Department of Water and Power (Joint Agencies) for review and comment. Should conditions significantly change, the CPUC will issue monthly supplemental reports this summer with input from the Joint Agencies to provide updates and revised gas balance analyses reflecting any new information.

Winter Lookback

Southern California experienced mostly mild temperatures this winter, had sufficient gas at mostly moderate prices, and enters the spring with a fair amount of gas in storage. Brief but substantial price spikes and supply concerns occurred in response to dramatic conditions outside the state in February, after which the SoCalGas gas system quickly returned to normal conditions. No other major gas system events occurred in Southern California during the period from November 1, 2020 through March 31, 2021 (the winter).

[3] Id, p. 4.

Cold weather is one of the main drivers of winter gas demand, as seen in Figure 1. Changing demand patterns due to Covid-19 slightly complicate the picture for winter 2020-21. Broadly speaking, weather-adjusted residential demand was up slightly, and commercial demand was down as Californians sheltered in place, resulting in little change to total demand. This figure plots SoCalGas' total system sendout, or demand, along with composite average temperatures for its service area.[4] System sendout rose above 3.5 Bcf only when daily composite weighted average temperatures dropped to or below 50°F. This happened on four days during this winter: once at the end of December, twice during a cold spell towards the end of January, and once in March before the cold spell in the Southwest. Sendout rose above 4 Bcf only once this winter, during the January cold spell.

Figure 1: Winter 2020-2021 Composite Average Temperatures and Sendout with Lines Marking the Southwestern Polar Vortex Cold Event

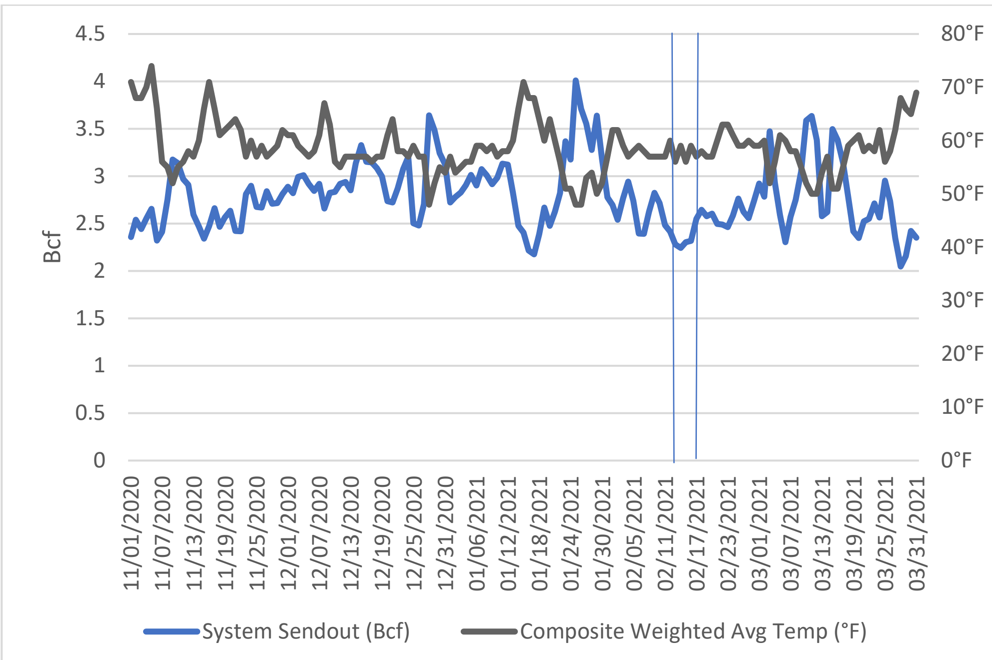
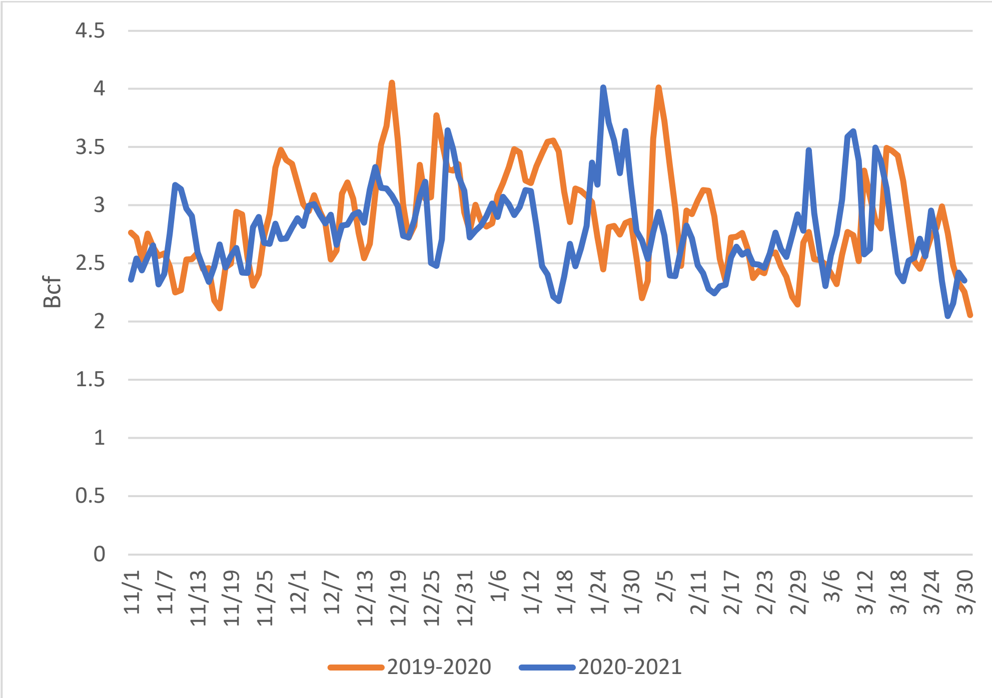


Figure 2 compares demand last winter with demand this winter. The range is similar, but this winter had fewer periods of high sendout. Thus, the average sendout from November through March is down from 2.9 Bcf in 2019-20 to 2.8 Bcf in 2020-21.

[4] Composite weighted average temperature can be found on SoCalGas' Envoy. The calculation first takes the daily temperature of several locations in the territory, then averages those into one number.

Figure 2: Comparison of Winter 2019-20 and Winter 2020-21 Demand

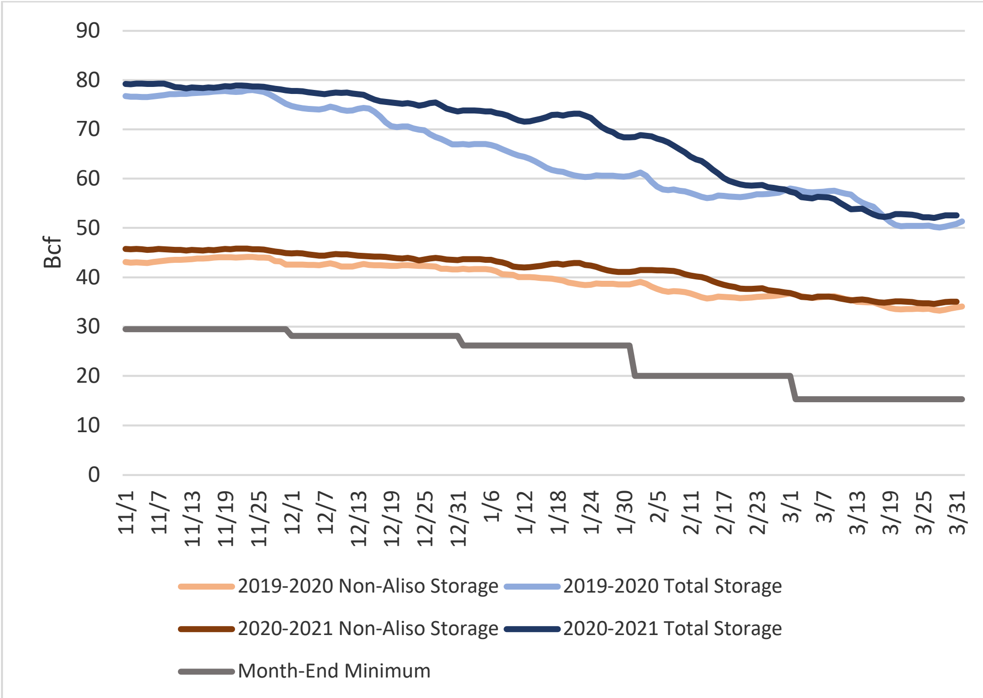


As in 2020, SoCalGas is approaching spring with ample gas in storage. March ended with gas storage inventories nearly three times the month-end minimum set by SoCalGas (52.6 Bcf vs. 15.3 Bcf). Storage inventories stayed higher than last winter's well into February. SoCalGas drew down storage substantially when unusual conditions occurred in Texas, which will be discussed further below. After this event, storage levels were about the same as the previous year.

Storage levels are well above the low inventories (45 percent or 38.3 Bcf) seen in March 2019. Like last year, the Aliso Canyon storage field was used intermittently throughout the winter as specified under the Aliso Canyon Withdrawal Protocol. For the first weeks of February, with Aliso Canyon inventory above 70 percent, SoCalGas was able to withdraw daily from this field under Condition 2 of the Aliso Canyon Withdrawal Protocol until the field's inventory fell below the 70 percent threshold.[5]

[5] Aliso Canyon Withdrawal Protocol: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2020/WithdrawalProtocol-Revised-April12020clean.pdf

Figure 3: Comparison of Winter 2019-20 and Winter 2020-21 Storage Inventory with Month-End Minimums



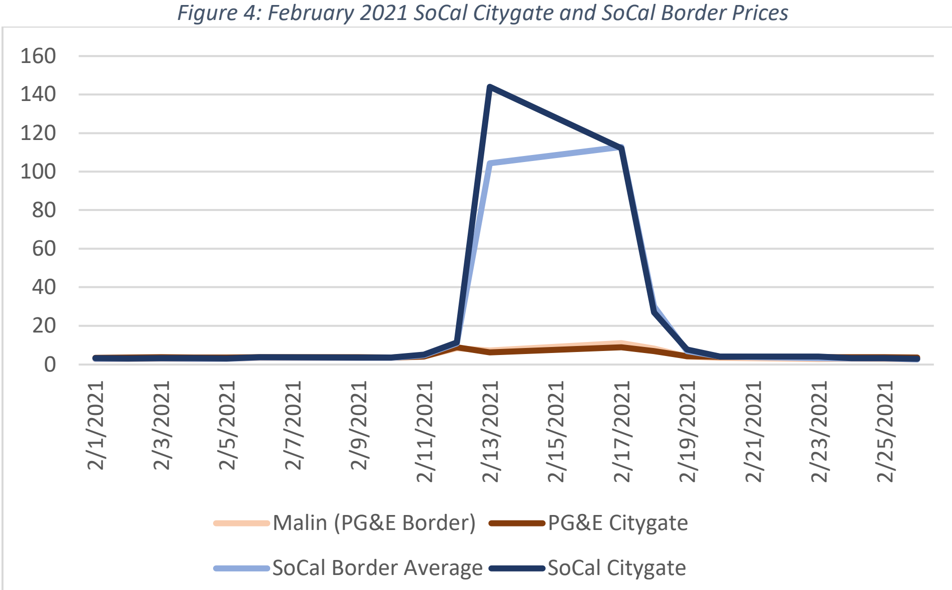
The main event affecting reliability this winter occurred outside California. Record cold temperatures impacted the Southwest and Midwest. Long-term policy decisions and unprepared physical infrastructure in Texas resulted in several days of interacting power and gas system outages. Multiple gas suppliers, especially those sourcing gas from the Permian basin (west Texas and southeastern New Mexico) did not fully deliver their firm supply contracts, leaving their customers with less gas than expected. The impact on Southern California was reduced gas availability and dramatically high spot prices for several days. Fortunately for Southern California gas customers, these events coincided with moderate in-state weather, resulting in moderate net impacts and no customer curtailment.

California receives approximately 90 percent of its gas from outside the state, making it vulnerable to supply disruptions beyond its control. For Southern California, a significant portion of this gas comes from the Permian Basin in Texas and New Mexico. Many gas wells in this area do not have heating equipment sufficient to operate during freezing conditions and/or require electricity from the grid to operate and therefore were not able to provide gas to the system during the extreme cold and power shutoffs that occurred. National gas production fell roughly 16.7 percent from above 90 billion cubic feet per day (Bcfd) to around 75 Bcfd, while Permian production fell about 25 percent from around 12 Bcfd to below 9 Bcfd. Some interstate pipelines experienced systemwide draft --or dropping pressure due to low volumes of gas -- and firm deliveries were cut in the face of unavailable supply. Receipt point utilization —the percentage of available pipeline capacity used on a given day—for gas entering Southern California pipelines dropped to just 47 percent on February 17 (Cycle 3).

Much of the country experienced record gas demand during this time but not California. These events, marked with vertical lines in Figure 1, occurred over February 13-18, which included the President's Day weekend. The long weekend, combined with moderate weather in Southern California, resulted in low regional demand, as seen in Figure 1. SoCalGas posted a curtailment watch for its Southern Zone from February 14 through 19, but no curtailment occurred.

Despite low demand, the impact of these events is clearly visible in spot prices. SoCal Citygate prices peaked at a daily average of $144 per million British thermal units (MMBtu) for gas traded on February 12 to flow on February 13-16. By the next trading day, February 17, average SoCal Border prices were slightly above SoCal Citygate, an unusual occurrence reflecting the extreme competition to buy that gas in colder parts of the country. This price differential also suggests that moderate demand and use of local storage reduced the cost impact of the event in Southern California. These dynamics are shown in Figure 4, which plots spot prices by beginning flow date. PG&E was much less effected by price shocks, as can be seen in Figure 4 below, due to its access to Canadian gas and the greater availability of storage in Northern California. Electricity spot prices in both Northern and Southern California also showed their sensitivity to gas prices and spiked to daily averages of $115 per megawatt hour (MWh) and $168/MWh, respectively, during this time.

Figure 4: February 2021 SoCal Citygate and SoCal Border Prices



With supplies running low, SoCalGas called Stage 4 low Operational Flow Orders (OFOs) on February 16-18, causing an additional layer of price effects for SoCalGas customers. Low OFOs are called when there is insufficient gas on the system. Higher stages mandate increasingly severe financial penalties for wholesale gas customers who do not match their gas deliveries with their gas burn. During a Stage 4 low OFO, wholesale gas customers must pay a penalty of $25 for each MMBtu of shortfall if they do not deliver enough gas to the system to fulfill at least 95 percent of their actual gas burn.

Nevertheless, storage withdrawals moderated these effects. Figure 5 shows how withdrawals filled in to meet demand when pipeline receipts dropped, with vertical lines marking February 13 and 18. Daily net withdrawals from SoCalGas storage peaked at 925 MMcfd on February 16, 28 percent higher than the prior week's peak. Total daily withdrawals (before netting out injections) peaked at 1,472 MMcfd as shown in Table 1. During the following week, demand was moderate, and SoCalGas was able to inject some gas into storage. While the utility's storage inventory was 7.6 Bcf above last year at the beginning of February, withdrawals during February drew inventory down to within a Bcf of last year's amount at the beginning of March (Figure 3).

Figure 5: February 2021 SoCal Daily Supply: Withdrawals and Pipeline Receipts

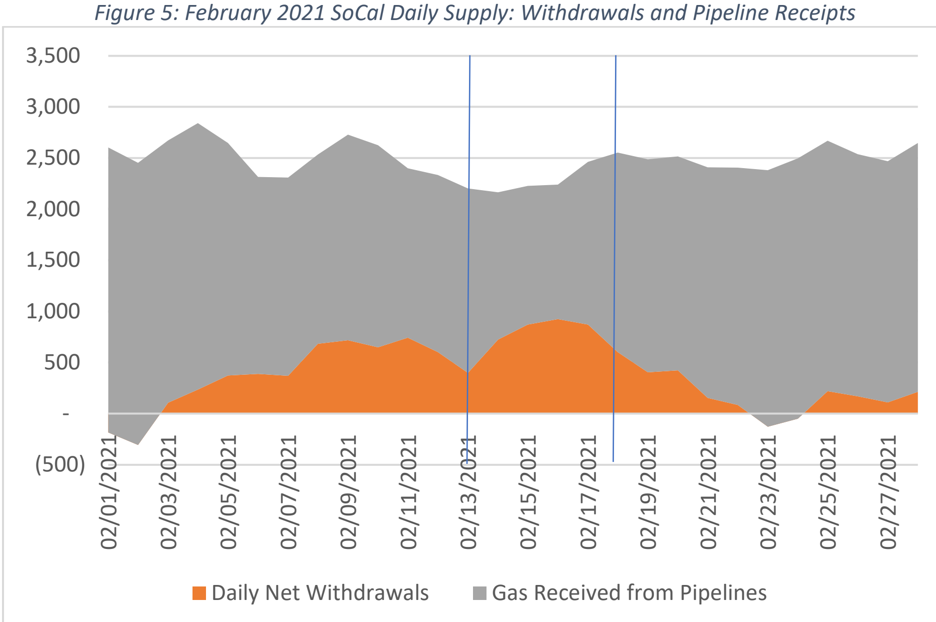


Table 3: Daily Storage Withdrawals February 10-19 (MMcfd)

	2/10	2/11	2/12	2/13	2/14	2/15	2/16	2/17	2/18	2/19
Non-Aliso	643	863	613	369	753	964	806	898	602	361
Aliso Canyon	376	350	177	156	335	508	360	356	238	197
Total	1,019	1,213	790	525	1,088	1,472	1,166	1,254	840	558

FERC and NERC have announced they are opening a joint inquiry into grid operations during the February 2021 cold weather, which will inevitably involve review of the gas system as well.[6] Reaction to these events is likely to influence energy policy for years to come.

Supply Outlook

Transmission Pipelines

There are three major transmission zones within the SoCalGas system—the Northern Zone, Southern Zone, and Wheeler Ridge Zone. The other two zones have a relatively minor impact on the system. The Line 85 Zone carries a small amount of gas, and the Coastal Zone has declined steadily in importance due to reduced output from California's gas fields. Operational changes

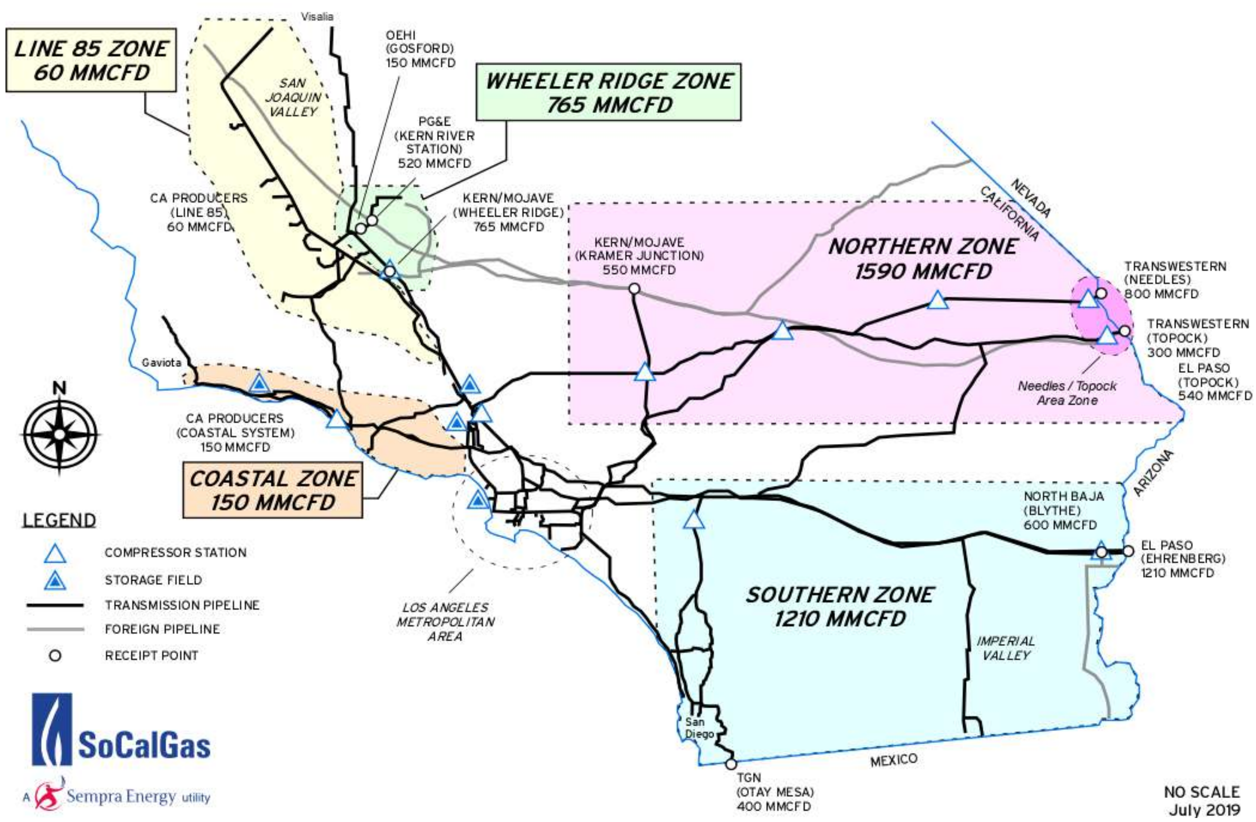
[6] https://www.ferc.gov/news-events/news/ferc-nerc-open-joint-inquiry-2021-cold-weather-grid-operations

within a zone can impact the overall transmission capacity of the system. Table 4 below illustrates the transmission zone operating capacities assumed to be available during summer 2021.

Table 4: Transmission Zone Assumed Operational Capacities (in MMcfd)

Northern Zone	**870**
North Needles	350
Topock	0
Kramer Junction	520
Wheeler Ridge Zone	**765**
Southern Zone	**670**
Blythe	670
Otay Mesa	0
Line 85 Zone	**60**

Figure 6: Receipt Points and Transmission Zone Nominal Capacity[7]



In the Northern Zone, Lines 235-2 and 3000 continue to operate at reduced pressure. Line 4000 is expected to be out of service for remediation work from May 1 through September 30.[8] With Line

[7] Zonal capacities shown do not reflect the most recent projected firm Backbone Transmission Service capacity offerings.

[8] SoCalGas System Maintenance Outlook for 2020/2021, posted March 24, 2021: https://scgenvoy.sempra.com/ebb/attachments/1616637477172_Maintenance_Outlook_3-24-21.pdf.

4000 out of service, the expected transmission capacity of the Northern Zone is 870 MMcfd, which is reflected in the gas balance below. Approximately 350 MMcfd of this amount is assumed to come through Line 235-2 and 520 MMcfd from Kramer Junction. 550 of firm capacity is available at Kramer Junction; however, if customers nominate up to 350 MMcfd through Line 235-2, then only 520 MMcfd can come from Kramer Junction. In addition, the gas balance analysis assumes that interruptible capacity will not be available at Kramer Junction while Line 4000 is out of service due to the effect of supply from Line 235-2.[9]

In the Southern Zone, SoCalGas has reduced the Ehrenberg receipt point from 1,210 to 980 MMcfd due to a longstanding pressure reduction related to its Pipeline Safety Enhancement Plan (PSEP) and the loss of a right-of-way on Line 2000. The Southern Zone still can accept 1,210 MMcfd if 230 MMcfd is delivered to Otay Mesa and there is sufficient demand within the zone. However, recent summers have seen the day-to-day Southern Zone capacity constrained by low demand rather than pipeline capacity. With no gas storage fields in the Southern Zone and limited capacity to deliver gas west towards Los Angeles, SoCalGas has reduced the amount of gas it accepts into the zone to approximate expected daily burn to avoid over-pressurizing the pipelines. In the gas balance analyses presented below, staff assumes 670 MMcfd is delivered through Ehrenberg from April through October, which reflects the historical average during periods of moderate demand. However, up to 980 MMcfd of capacity can be delivered at Ehrenberg during high demand periods. According to SoCalGas' Envoy, Southern System receipts have averaged approximately 822 MMcfd since the beginning of April. The higher than average receipts observed in the last few weeks may be a result of customers maximizing scheduled receipts to inject gas into storage and residual core heating demand that typically occurs in early April. Average receipts may drop in May and June as storage begins to fill up and core demand drops. Staff anticipates higher than average receipts during periods of hot weather which will primarily be driven by electric generation demand. Staff assumes zero supply is delivered through Otay Mesa from April through October.

The Wheeler Ridge Zone can receive up to 810 MMcfd under certain conditions but only 765 MMcfd on a firm basis. This increase to 810 MMcfd is only possible if Line 235-2 is out of service, thus removing downstream competition on the pipelines. Since Line 235-2 is assumed to be in service, the gas balance analysis below assumes 765 MMcfd of capacity at Wheeler Ridge.

Lastly, SoCalGas de-rated Line 85, which delivers gas from California natural gas producers, as part of its Pipeline Safety Enhancement Plan.[10] The de-rating reduced the pipeline's capacity from 160 to 60 MMcfd. However, since the pipeline was only delivering about 80 MMcfd before the derating due to the decline in California gas production, the actual impact of this change is roughly 20 MMcfd.

[9] See discussion of this issue on page 3 of SoCalGas Summer 2021 Technical Assessment: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2021/2021%20SUMMER%20TECHNICAL%20ASSESSMENT%201April21%20[Final].pdf

[10] See SoCalGas Advice Letter 5493-G: https://www.socalgas.com/regulatory/tariffs/tm2/pdf/5493.pdf.

Gas Storage Facilities

Table 5 below compares the amount of gas in storage at the end of March in 2020 and 2021. Aliso Canyon's maximum allowable inventory of 34 billion cubic feet [11] remains unchanged.

Table 5: Total SoCalGas Storage Inventory

Bcf	March 31, 2020	March 31, 2021
Non-Aliso	34.1	35.1
Aliso Canyon	17.8	17.5
Total	51.9	52.6

As shown, there is no marked difference between the combined non-Aliso and Aliso Canyon inventory levels in March 2020 and 2021. On March 31, 2020, the combined non-Aliso fields were approximately 67 percent full, and Aliso Canyon was 52 percent full. On March 31, 2021, the combined non-Aliso fields were 70 percent full, and Aliso Canyon was 51 percent full.

As discussed in the Winter 2020-21 Southern California Reliability Assessment, SoCalGas undertook well maintenance activity throughout the winter in order to comply with the new April 1, 2021, deadline for well inspections mandated by recent CalGEM regulations. This ongoing maintenance led to reductions in injection and withdrawal capacities compared to previous years. However, as shown in Table 2 above, SoCalGas approaches the spring injection season in a good position.

Gas Balance Analysis and Summer Peak Day Analysis

Gas demand figures for the winter are taken from the forecasts in the *2020 California Gas Report*.[12] Staff prepared gas balances in order to provide an assessment independent of SoCalGas' own assessment.[13] 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 identifies the daily difference, or margin, between capacity (or supply) and demand to determine in general whether capacity is enough to meet demand. It also simulates the impact to month-end storage inventory levels from average daily storage injections and withdrawals.

[11] SB 380 added Section 715 to the California Public Utilities Code, which requires the CPUC to determine "the range of working gas necessary [in Aliso Canyon] to ensure safety and reliability for the region and just and reasonable rates in California. On July 2, 2018, the CPUC directed SoCalGas to maintain up to 34 Bcf of inventory due to "unprecedented level of outages on the SoCalGas system," among other reasons. An archive of the CPUC's 715 Reports can be found here: http://www.cpuc.ca.gov/General.aspx?id=6442457392. Section 715 expired on January 1, 2021. The CPUC issued Decision (D) 20-11-044 in Investigation 17-02-002 to maintain the interim maximum Aliso Canyon storage capacity at 34 Bcf. Phase 2 of I.17-02-002, will provide additional relevant analysis and include reconsideration of the maximum allowable inventory at Aliso Canyon.

[12] The *2020 California Gas Report* and its supporting workpapers can be found at: https://www.socalgas.com/regulatory/cgr.shtml.

[13] The Gas Balance framework in use for the purposes of this report was initially developed by Aspen Environmental for the California Energy Commission. This analysis tool has been used in several prior assessments, including those by the Joint Agencies as well as the CPUC.

A gas balance does not simulate operations hydraulically to determine constraints or assess hourly operations.

Demand forecasts are for average daily consumption for each month under average temperature/base hydro and cold weather/dry hydro weather scenarios. Forecasts indicate that this summer may be both hot and dry. However, the California Gas Report does not include demand forecasts under hot and dry hydro conditions. Thus, staff included a gas balance scenario for cold/dry hydro conditions, since demand is higher than under base hydro conditions because gas-fired electric generation is needed more frequently when less hydroelectricity is available. In both cases, there will be days in the summer that will have higher or lower demand than the averages shown.

In previous reports, staff have sought to demonstrate a positive deliverability margin of roughly 15 percent in the gas balances, which would mean there is more capacity than demand. This buffer is intended to ensure that the system retains reserve capacity to deal with unplanned outages or days with above-average demand. While the gas balance scenarios do not automatically discount pipeline capacity supply, analyses of past pipeline utilization have shown that customers rarely use 100 percent of pipeline capacity. However, when total system pipeline capacity is constrained, pipeline utilization (as a percentage of pipeline capacity) increases compared to historical norms. Both scenarios include injection limits posed by the semiannual storage field shut-ins, which are required by California Geologic Energy Management Division (CalGEM, formerly DOGGR) regulations. In addition, both scenarios consider the injection capacities available to customers in the summer under the current Triennial Cost Allocation Proceeding (TCAP) rules.[14]

The first gas balance scenario presented in the appendix below assumes that weather is normal and Line 4000 is out of service from May 1 through September 30 for remediation work; all other lines are assumed to be in service from April through October. The non-Aliso fields become full by the end of June, and Aliso Canyon becomes full by the end of July. The gas balance scenario meets demand in all months but is unable to maintain a 15 percent reserve margin during any of the summer months. Storage withdrawals from the non-Aliso fields and Aliso Canyon are initiated to meet customer demand on average weather days in August and September. As a result, the storage fields become slightly drawn down by October.

The second gas balance scenario presented in the appendix assumes cold weather and dry hydro conditions. Line 4000 is out of service from May 1 through September 30 for remediation work; all other lines are assumed to be in service from April through October. The non-Aliso fields become full by the end of June. However, Aliso Canyon does not fill up to its maximum authorized capacity of 34 Bcf. Both non-Aliso and Aliso withdrawals are needed in July, August, and September. As a result, the storage fields become more significantly drawn down by October. The gas balance is unable to maintain any reserve margin throughout the summer months.

[14] Appendix A to the TCAP decision, D.20-02-045: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M324/K884/324884522.PDF

In addition to the above analysis, staff performed a summer high sendout day analysis to estimate whether assumed supplies would be sufficient to meet a high demand day. Staff did not do a hydraulic peak day analysis, so these daily figures do not capture peaks in hourly demand that could increase the need for storage.

The high summer demand day is forecasted to occur in September and is driven primarily by peak demand for electric generation. This analysis is different from the analyses presented in the gas balance because the latter is based on average gas demand that does not account for a potential increase in gas use due to peak electric demand.

Column (a) below in Table 6 includes the forecasted summer 2021 high demand figure from the *2020 California Gas Report*. Column (b) shows the pipeline capacity assumed to be available while Line 4000 is out of service. In Column (c), the projected withdrawal capacity is the combined capacity allocated to core customers and the balancing function for the summer months, if Aliso's withdrawal capacity is available.[15] The projected surplus in Column (e) represents the remaining withdrawal capacity after projected withdrawals occur to meet the peak demand. Table 7 provides the same information, but Column (c) shows the projected withdrawal capacity if Aliso Canyon is unavailable.

For the pipeline capacity, staff used the same numbers as in the gas balance analyses except for in the Southern Zone. Since the Southern Zone is typically constrained by demand rather than pipeline capacity in the summer, staff expects it to be able to carry more gas on a peak day than an average day. Staff assumed approximately 980 MMcfd of capacity could become available through the Ehrenberg receipt point in the Southern Zone if there is enough demand. Staff included this amount in the pipeline capacity assumed to be available in Tables 6, 7, 8, and 9. It is also worth noting that peaks in hourly demand can cause an increased need for withdrawals from storage that is not captured in these daily figures.

Table 6: Summer High Demand Day with Line 4000 Out of Service and Aliso Canyon Available (MMcfd)

	(a) Summer Peak Day Demand	(b) Pipeline Capacity	(c) Projected Withdrawal Capacity	(d) Projected System Capacity (d=b+c)	(e) Surplus/ Shortfall (e=d-a)
September	3,160	2,675	1,240	3,915	755

[15] TCAP Appendix A, Storage Capacity Allocation, Table 2: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M328/K301/328301730.pdf

Table 7: Summer High Demand Day with Line 4000 Out of Service and Aliso Canyon Unavailable (MMCFd)

	(a) Summer Peak Day Demand	(b) Pipeline Capacity	(c) Projected Non-Aliso Withdrawal Capacity	(d) Projected System Capacity (d=b+c)	(e) Surplus/ Shortfall (e=d-a)
September	3,160	2,675	750	3,425	265

The demand levels observed during the record-breaking heatwave of August 2020 were higher than the 2021 peak summer demand forecasted in the California Gas Report; actual demand reached 3,175 MMcfd on August 18, 2020. Approximately 50 percent of that demand was a result of electric generation activity and 17 percent was core gas demand. All four SoCalGas gas storage fields were on withdrawal to meet the high demand. Energy prices hit all-time record highs as the Northwest, Southwest, and California were all in competition for any available energy resources in the region. In addition, solar generation came in weaker than expected. One risk factor that did not come into play during the rolling blackouts but is something to consider when planning for summer reliability is the potential for reductions in solar output due to smoke from wildfires. During the first two weeks of September 2020, solar-powered generation in the CAISO region dropped nearly 30 percent from the July 2020 average due to wildfire smoke.[16] Should a heatwave occur during wildfire season, reduced solar output may increase reliance on gas-fired generation.

In Tables 8 and 9 below, staff compares the actual August 18, 2020, demand levels with the projected pipeline capacity assumed to be available while Line 4000 is out of service this summer. Since actual demand on August 18, 2020, is comparable to the 2021 summer projected peak day demand, the SoCalGas system should be able to meet that level of demand with a combination of flowing gas supply and withdrawal capacity. However, as shown in Table 8, there will be a tighter margin between available supply and withdrawal capacity if Aliso Canyon is not available.

Table 8: 8/18/20 High Demand Day with Line 4000 Out of Service and Aliso Canyon Available (MMcfd)

(a)[17] Actual Demand on 8/18/20	(b) Pipeline Capacity	(c) Projected Withdrawal Capacity	(d) Projected System Capacity (d=b+c)	(e) Surplus/ Shortfall (e=d-a)
3,175	2,675	1,240	3,915	740

Table 9: 8/18/20 High Demand Day with Line 4000 Out of Service and Aliso Canyon Unavailable (MMcfd)

[16] US EIA "today in Energy" Notice: https://www.eia.gov/todayinenergy/detail.php?id=45336
[17] Approximately 50 percent of the demand was a result of electric generation activity.

(a)[18] Actual Demand on 8/18/20	(b) Pipeline Capacity	(c) Projected Withdrawal Capacity	(d) Projected System Capacity (d=b+c)	(e) Surplus/ Shortfall (e=d-a)
3,175	2,675	750	3,425	250

CPUC Actions

The Aliso Canyon storage field's long-term fate and short-term inventory limit are being examined in Investigation (I.) 17-02-002. On February 3, 2021, CPUC Energy Division released the Modeling Report for Phase 2 of that proceeding.[19] The modeling showed that, under 1-in-10 peak planning conditions, reliability could be maintained with an interim inventory limit of 41.2, 54.9 or 68.6 Bcf, depending on how much gas pipeline capacity is assumed to be available. If there is less pipeline supply available, then SoCalGas would rely more heavily on its storage inventory to meet peak demand levels. Inversely, if there is more pipeline supply available, then SoCalGas would not need as much storage to meet peak demand. Concurrently, in Phase 3 of the proceeding, an independent consultant is examining portfolios of resources (including conservation) that could replace the need for Aliso Canyon by 2027 or 2035, with research scheduled to conclude during 2021. Evidentiary hearings have begun in I.19-06-016, which is examining whether SoCalGas violated Commission regulations with respect to the 2015 gas leak at Aliso Canyon.

Proceeding R.20-01-007 continues to examine policies related to long-term gas planning. The current phase of the proceeding is addressing reliability requirements, enforcement or incentive mechanisms, electricity price impacts, OFO rule changes, expected reliability impacts of the LNG export facility, and how to address potential electric reliability impacts of generators' reliance on the spot market. Energy Division staff released a Workshop Report and Staff Recommendations after holding workshops for Phase 1 in July 2020. [20] Parties submitted motions for evidentiary hearings and the CPUC is currently considering next steps in the proceeding.

Lastly, effective February 1, 2021, and in compliance with the 2020 TCAP decision, D.20-02-045, SoCalGas changed the Cycle 6 nomination deadline, from 9:00 p.m. on the Gas Day to 9:00 p.m. one calendar day after the Gas Day. It also changed the imbalance trading deadline from 9:00 p.m. on the Gas Day to 9:00 p.m. on the day following the close of Cycle 6.[21] This change allows customers more time to trade imbalances and may reduce their imbalance penalties.

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[18] Id.

[19] Aliso OII Phase 2 Modeling Report: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2021/I_1702002_Phase2ModelingReport_3-8-21_unredacted.PDF

[20] R. 20-01-007 Track 1A and Track 1B Workshop Report and Staff Recommendations: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M348/K035/348035848.PDF

[21] SoCalGas Envoy Critical Notice of Cycle 6 changes: https://scgenvoy.sempra.com/ebb/attachments/1610483820458_Cycle__6_Nomination_Deadline_Change.pdf

Appendix

SoCalGas Monthly Gas Balance
Scenario A
Base Hydro Year

SoCalGas Monthly Gas Balance NORMAL WEATHER		April	May	June	July	Aug	Sept	Oct
California Gas Report 2021 Demand (MMcfd)								
Core		976	734	630	594	595	613	693
Noncore including EG		910	879	950	1,264	1,539	1,440	1,209
Wholesale & International		281	232	227	340	400	373	348
Co. Use and LUAF		28	24	23	28	32	31	29
Subtotal Demand		2,195	1,869	1,830	2,226	2,566	2,457	2,279
Storage Injection (Non-Aliso Fields)		85	182	210	0	0	0	90
Storage Injection (Aliso)		100	125	200	130	0	0	50
Storage Injection Total		*185*	*307*	*410*	*130*	*0*	*0*	*140*
System Total Throughput		2,380	2,176	2,240	2,356	2,566	2,457	2,419
Supply (MMcfd)								
California Line 85 Zone		60	60	60	60	60	60	60
Wheeler Ridge Zone		765	765	765	765	765	765	765
Blythe (Ehrenberg) into Southern Zone		670	670	670	670	670	670	670
Otay Mesa into Southern Zone		0	0	0	0	0	0	0
Kramer Junction into Northern Zone		520	520	520	520	520	520	520
North Needles into Northern Zone		350	350	350	350	350	350	350
Topock into Northern Zone		90	0	0	0	0	0	90
Sub Total Pipeline Receipts		2,455	2,365	2,365	2,365	2,365	2,365	2,455
Storage Withdrawal (Non-Aliso Fields)		0	0	0	0	130	70	0
Storage Withdrawal (Aliso)		0	0	0	0	71	22	0
Total Supply		2,455	2,365	2,365	2,365	2,566	2,457	2,455
DELIVERABILITY BALANCE (MMcfd)		75	189	125	9	0	0	36
Reserve Margin		3%	9%	6%	0%	0%	0%	1%
Non-Aliso Month-End Storage Inventory (Bcf)	35.1	38	43	50	50	46	43	46
Aliso Month-End Storage Inventory (Bcf)	17.5	21	24	30	34	32	32	33
Total Storage Inventory	52.6	58	68	80	84	78	75	79

SoCalGas Monthly Gas Balance

Scenario B

Dry Hydro Year

SoCalGas Monthly Gas Balance NORMAL WEATHER		April	May	June	July	August	September	October
California Gas Report 2020 Demand (MMcfd)								
Core		1041	762	636	595	596	616	713
Noncore including EG		940	946	1,049	1,408	1,643	1,538	1,232
Wholesale & International		305	246	254	359	420	395	358
Co. Use and LUAF		29	25	25	30	34	33	29
Subtotal Demand		2,315	1,979	1,964	2,392	2,693	2,582	2,332
Storage Injection (Non-Aliso Fields)		85	182	210	0	0	0	77
Storage Injection (Aliso)		55	125	190	90	0	0	46
Storage Injection Total		*140*	*307*	*400*	*90*	*0*	*0*	*123*
System Total Throughput		2,455	2,286	2,364	2,482	2,693	2,582	2,455
Supply (MMcfd)								
California Line 85 Zone		60	60	60	60	60	60	60
Wheeler Ridge Zone		765	765	765	765	765	765	765
Blythe (Ehrenberg) into Southern Zone		670	670	670	670	670	670	670
Otay Mesa into Southern Zone		0	0	0	0	0	0	0
Kramer Junction into Northern Zone		520	520	520	520	520	520	520
North Needles into Northern Zone		350	350	350	350	350	350	350
Topock into Northern Zone		90	0	0	0	0	0	90
Sub Total Pipeline Receipts		2,455	2,365	2,365	2,365	2,365	2,365	2,455
Storage Withdrawal (Non-Aliso Fields)		0	0	0	80	170	110	0
Storage Withdrawal (Aliso)		0	0	0	37	158	107	0
Total Supply		2,455	2,365	2,365	2,482	2,693	2,582	2,455
DELIVERABILITY BALANCE (MMcfd)		0	79	1	0	0	0	0
Reserve Margin		0%	3%	0%	0%	0%	0%	0%
Non-Aliso Month-End Storage Inventory (Bcf)	35.1	38	43	50	47	42	39	41
Aliso Month-End Storage Inventory (Bcf)	17.5	19	23	29	30	25	22	24
Total Storage Inventory	52.6	57	66	78	77	67	61	65