California Public Utilities Commission

Aliso Canyon Working Gas Inventory, Production Capacity, Injection Capacity, and Well Availability for Reliability

DRAFT Summer 2018 Supplemental Report

Public Utilities Code Section 715

June 18, 2018

Energy Division

Executive Summary

In the aftermath of the 2015 gas leak at the Aliso Canyon natural gas storage facility (Aliso), Senate Bill 380 added Section 715 to the Public Utilities Code, which requires the California Public Utilities Commission (CPUC) to determine the range of Aliso inventory necessary to ensure safety, reliability, and just and reasonable rates. In this update to the 715 Report,[1] Energy Division recommends that the maximum allowable Aliso inventory be increased from 24.6 to 34 billion cubic feet (Bcf). Energy Division deems this increase to be necessary due to 1) continuing pipeline outages on the Southern California Gas Company (SoCalGas) system; 2) consideration of the impact that declines in inventory at the non-Aliso storage fields have on their withdrawal capacity; 3) an examination of whether monthly 1-in-10 peak day demand can be met with forecasted storage inventory levels; and 4) limited injection capacity at the non-Aliso fields, which makes it difficult to inject gas into storage.

This update to the 715 Report focuses on whether SoCalGas can meet all system demand on a 1-in-10-year peak day. Previous versions of the report calculated what system demand would be if electric generators were curtailed to the minimum generation level sustainable without a disruption in electric service. Curtailing electric generators to minimum generation is an emergency measure. As such, it was appropriate to consider when no Aliso injection was possible. However, the CPUC's established standard is that the SoCalGas system should be designed to meet both core and noncore demand on a peak day that is expected to occur once every 10 years. Deviating from that standard in the absence of an emergency puts an undue burden on electric generators and ratepayers. Furthermore, the California Independent System Operator (California ISO) has indicated that it faces "a much higher potential for challenging summer operating conditions" than in previous summers.[2] Requiring its electric generators to run at minimum generation would exacerbate an already difficult situation.

Another change in this update compared to previous versions is that it looks beyond the coming season to both summer 2018 and winter 2018-19. This change in strategy was prompted by the results of the Aliso Canyon Risk Assessment Technical Report Summer 2018 (Summer 2018 Technical Assessment), which found that in addition to the risks to energy reliability expected for summer 2018, extensive pipeline outages on the SoCalGas system may make it difficult for the utility to fill its gas storage fields to a level sufficient to ensure energy reliability this winter.

In addition to Summer 2018 Technical Assessment, the analysis in this report is based on the findings of the Aliso Canyon Winter Risk Assessment Technical Report (Winter 2016-17 Technical Assessment); the Aliso Canyon Winter Risk Assessment Technical Report 2017-18 Supplement (Winter 2017-18 Technical Assessment); the experience of

[1] The last 715 Report was published on December 11, 2017. All previous versions of the 715 Report can be found at: http://www.cpuc.ca.gov/General.aspx?id=6442457392.

[2] California Independent System Operator's 2018 Summer Loads & Resources Assessment, p.3.

winter 2017-18; and confidential withdrawal curves for the four SoCalGas storage fields provided by the utility.[3]

In this update, Energy Division examines two possible pipeline capacity scenarios, as shown in the table below. Each pipeline scenario is shown under two sets of weather conditions in order to determine the amount of Aliso inventory that is required to meet 1-in-10-year peak day demand in every month of winter 2018-19.

Table ES-1: Scenarios Examined (MMcfd)

	Pipeline Capacity	Weather
A-average	2,696	Avg. summer/avg. winter
A-cold	2,696	Avg. summer/cold winter
B-average	3,296	Avg. summer/avg. winter
B-cold	3,296	Avg. summer/cold winter

The first pipeline capacity scenario assumes that current outages, as detailed in the Summer 2018 Technical Assessment, continue and that an additional 180 MMcfd of pipeline capacity is lost in September.[4] Under the "A" Scenarios, peak demand cannot be met without curtailments, even if Aliso were filled to the maximum inventory the Division of Oil, Gas, and Geothermal Resources (DOGGR) has deemed to be safe. The pipeline outages assumed in the A Scenarios also make it difficult to fill Aliso to a level that provides winter-long support for system reliability. In the Gas Balances produced for this analysis, the maximum achievable Aliso inventory under the A Scenarios was 31 Bcf. In contrast, under the "B" Scenarios, which assume that Line 4000 returns to full capacity in September and there are no additional pipeline outages, the need to use Aliso to meet peak demand is greatly reduced and the ability to fill storage is enhanced.

Further complicating matters is the fact that early summer — when demand is still relatively low— is the key time for injecting gas into storage under the reduced pipeline capacity scenario. Therefore, Energy Division cannot wait for more information about which pipeline scenario is more likely — a recommendation must be made early in the summer. In reaching its recommendation, Energy Division has weighed the risks to Southern California reliability in winter 2018-19 with the uncertainty regarding the pipeline system and the practical limitations on injecting gas into Aliso.

Finally, it is important to emphasize that the 715 Report is intended to provide analysis of what is required to manage Southern California gas reliability over the short term. The determination of whether the storage facility will be used over the long term is the subject of CPUC proceeding I.17-02-002.

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[3] The Technical Assessments were created by the Aliso Canyon Technical Assessment Group, which consists of the CPUC, the California Energy Commission, the California ISO, and the Los Angeles Department of Water and Power. All previous Technical Assessments can be found at: http://cpuc.ca.gov/alisoassessments/.

[4] The loss of pipeline capacity is based on the assumptions SoCalGas used in Table 2 of its own Summer 2018 Technical Assessment, which can be found in Appendix B of Advice Letter 5275-A.

Background
A major gas leak was discovered at the Southern California Gas Company's Aliso Canyon natural gas storage facility on October 23, 2015. On January 6, 2016, the governor ordered SoCalGas to maximize withdrawals from Aliso Canyon to reduce the pressure in the facility. The California Public Utilities Commission subsequently required SoCalGas to leave 15 Bcf of working gas in the field that could be withdrawn in an emergency. On May 10, 2016, Senate Bill (SB) 380 was approved. Among other things, the bill:

1. Prohibited injection into Aliso until a safety review was completed and certified DOGGR with concurrence from the CPUC;
2. Ordered Aliso wells to be remediated so that gas flows only through the interior metal tubing and not through the annulus between the tubing and the well casing ("tubing-only flow");
3. Required DOGGR to set the maximum and minimum reservoir pressure; and
4. Charged the CPUC with determining the range of working gas necessary to ensure safety and reliability and just and reasonable rates; this statutory requirement may be found in Public Utilities Code Section 715.[5]

On July 19, 2017, DOGGR certified, and the Executive Director of the Commission concurred, that the required inspections and safety improvements had been completed and injections could resume. DOGGR found that the facility could be safely operated at pressures between a minimum of 1,080 pounds per square inch absolute (psia) and a maximum of 2,926 pounds psia.[6] These pressures translate into an inventory of working gas that ranges from 0 Bcf to approximately 68.6 Bcf.[7]

The CPUC has published four previous versions of this report — known informally as the "715 Report" — which determines the range of working gas needed to ensure safety, reliability, and reasonable rates as required by Section 715. The allowable range has changed with each iteration of the report due to changing system conditions and the CPUC's evolving understanding of the available information. Specifically, the statute requires the CPUC to determine:

1. The range of working gas necessary at the Aliso Canyon storage facility to ensure safety and reliability at just and reasonable rates in California;
2. The amount of natural gas production at the facility needed to meet safety and reliability requirements;

[5] SB 380 added Section 715 to the Public Utilities Code. All statutory references in this report are to the Public Utilities Code unless otherwise noted.
[6] DOGGR Updated Comprehensive Safety Review Findings, Enclosure 1.
[7] This figure is based on an April 19, 2018, email from DOGGR to the CPUC.

3. The number of wells and associated injection and production capacity required; and
4. The availability of sufficient natural gas production wells that have satisfactorily completed required testing and remediation.

Items 3 and 4 have become less critical as more wells have satisfactorily completed required testing and remediation. Therefore, this report focuses primarily on Items 1 and 2: the range of working gas necessary (inventory) and the amount of natural gas production needed (withdrawal capacity). Nonetheless, a brief update on Items 3 and 4 is provided at the end of this report.

This update incorporates information acquired since the last 715 Report was published on December 11, 2017, as well as the results of previous analyses. It is based on the findings of the Winter 2016-17 Technical Assessment; the Winter 2017-18 Technical Assessment; the Summer 2018 Technical Assessment; the experience of winter 2017-18; and confidential withdrawal curves for the four SoCalGas storage fields.

The 715 Report is intended to provide analysis of what is required to manage Southern California gas reliability over the short term. The determination of whether the storage facility will be used over the long term is the subject of CPUC proceeding I.17-02-002.

Lessons from Winter 2017-18

Winter 2017-18 started off under challenging circumstances due to the October 1, 2017, rupture on Line 235-2. After the rupture, SoCalGas took the adjacent Line 4000 out of service for inspection and repair.[8] With little time to inject additional gas into storage before the official start of the winter season on November 1, the CPUC allowed a modest expansion of the range of working gas at Aliso, from 14.8-23.6 Bcf[9] to 0-24.6 Bcf.[10]

With pipeline capacity reduced by outages, the gas balance forecasts performed in November for the 2017-18 Winter Technical Assessment[11] showed that storage inventory would be insufficient to meet peak demand in an average winter and that it would be woefully inadequate for a cold winter. Fortunately, most of winter 2017-18 was exceptionally warm, and SoCalGas withdrew very little gas from storage until the region experienced a sustained cold snap beginning in mid-February. Even with the cold snap, there was nearly as much gas in the non-Aliso fields at the end of March as the average forecast predicted for December. However, even with much higher storage inventory levels than anticipated, electric generators were curtailed between February 20 and March 6, 2018.

[8] These outages were in addition to an existing outage on Line 3000 and a reduction in capacity on Line 2000.
[9] July 19, 2017, 715 Report.
[10] December 11, 2017, 715 Report.
[11] 2017-18 Winter Technical Assessment, pp 22-23.

Table 1 below compares the forecasted month-end inventory at the non-Aliso fields from the November gas balances to actual month-end inventories in winter 2017-18.

Table 1: Forecasted vs. Actual Non-Aliso Month-End Inventory: Winter 2017-18 (Bcf)

	November	December	January	February	March
Average Winter	42	27	21	17	17
Cold Winter	36	21	5	1	1
Actual	46	41	35	29	26

Withdrawal capacity is directly related to storage inventory. At higher inventories, storage fields experience higher pressures, which allow the gas to be withdrawn at faster rates. Withdrawal rates decline rapidly as the amount of gas in inventory drops. Table 2 below calculates what the combined withdrawal rate for the non-Aliso fields would be at the inventory levels shown in Table 1. In all three scenarios, by March withdrawal capacity has fallen significantly. In the Cold Winter scenario, withdrawal capacity drops far below critical levels.

Table 2: Estimated Non-Aliso Withdrawal Capacity at Winter 2017-18 Forecasted and Actual Month-End Inventory Levels (MMcfd)[12,13]

	November	December	January	February	March
Average Winter	1,048	878	786	666	666
Cold Winter	1,033	806	487	225	225
Actual	1,065	1,060	1,021	809	762

These declines in withdrawal capacity have a significant impact on the SoCalGas system's ability to meet 1-in-10 peak day demand. However, previous versions of the 715 Report mentioned, but did not explicitly calculate, these impacts. In part this was because, prior to the pipeline outages, the drawdown in storage was not as extreme since a greater portion of daily demand could be met with flowing gas supplies. Similarly, both the Winter 2016-17 and the Winter 2017-18 Technical Assessments use a

[12] Withdrawal rates for individual fields are confidential. These estimates combine the differing withdrawal rates at the three non-Aliso fields at estimated levels of inventory and are for illustrative purposes only. Assumptions have been made about how inventory would be allocated between storage fields. Aggregate withdrawal capacity may differ at similar combined inventory levels because of different assumptions about how the inventory is allocated. For example, if more inventory is assumed to be at Honor Rancho in Estimate A compared to Estimate B, combined withdrawal capacity will be different, even if combined inventory is the same. The withdrawal rates used in the calculations underlying these estimates are based on confidential withdrawal curves provided by SoCalGas in fall 2017 for Honor Rancho and La Goleta. SoCalGas did not provide a withdrawal curve for Playa del Rey at that time, so the estimated withdrawal capacity for that field is based on weekly reliability reports provided to Energy Division by SoCalGas.

[13] Honor Rancho is limited to a maximum of 541 MMcfd of withdrawal capacity based on the hydraulic modeling found on page 19 of the 2016 Aliso Canyon Winter Risk Assessment Technical Report. Modeling found that Honor Rancho would operate at a higher withdrawal capacity on an hourly basis but that it wouldn't be used every hour of the day. This limitation only has an impact early in winter.

static number — 1,181 MMcfd — in their calculations of non-Aliso withdrawal capacity on a peak day.[14] Although the gas balances included in the Technical Assessments forecast how storage inventory declines throughout the season, the impact of the decline on withdrawal capacity is not explicitly calculated. This report seeks to make the connection between inventory and withdrawal capacity explicit and to consider whether drawdowns in storage inventory impact the system's ability to meet peak-day demand late in the winter.

Table 3: Ability to Meet 2017-18 Winter Monthly 1-in-10 Peak Day Forecast[15] with Estimated Month-End Non-Aliso Withdrawal Capacity (MMcfd)

	(a) 1-in-10 Peak Day Demand	(b) Total Pipeline Capacity	(c) Estimated Withdrawal Capacity	(d) Total System Capacity (d=b+c)	(e) Surplus/ Shortfall (e=d-a)
November					
Average Forecast	4,263	2,476	1,048	3,524	-739
Cold Forecast	4,263	2,476	1,033	3,509	-754
Actual	4,263	2,476	1,065	3,541	-722
December					
Average Forecast	4,955	2,736	878	3,614	-1,341
Cold Forecast	4,955	2,736	806	3,542	-1,413
Actual	4,955	2,736	1,142	3,878	-1,077
January					
Average Forecast	4,955	2,906	786	3,692	-1,263
Cold Forecast	4,955	2,906	487	3,393	-1,562
Actual	4,955	2,906	1,021	3,927	-1,028
February					
Average Forecast	4,639	2,906	666	3,572	-1,067
Cold Forecast	4,639	2,906	225	3,131	-1,508
Actual	4,639	2,906	809	3,715	-924
March					
Average Forecast	4,428	2,906	666	3,572	-856
Cold Forecast	4,428	2,906	225	3,131	-1,297
Actual	4,428	2,906	762	3,668	-760

Table 3 above shows in column (b) the pipeline capacity assumed in the Winter 2017-18 Technical Assessment[16] and then in column (c) substitutes the estimated withdrawal

[14] This estimate came out of the hydraulic modeling done for the Winter 2016 Technical Assessment (p. 19). The hydraulic modeling found that the withdrawal capacity of the fields was as follows: La Goleta: 340 MMcfd; Playa del Rey: 300 MMcfd; and Honor Rancho: 541 MMcfd.
[15] Winter 2017-18 peak day forecasts were created for the 2016 California Gas Report.

capacities from Table 2 above for the static number (1,181 MMcfd) used in the Winter 2016-17 and Winter 2017-18 Technical Assessments. As withdrawal capacity declines, it becomes more difficult to meet the 1-in-10-year peak day design standard. The shortfalls displayed in column (e) represent the amount of gas from Aliso and/or curtailments that would have been required if a peak day had occurred. Given the existing pipeline outages, the SoCalGas system could not have supported 1-in-10 peak demand in any month, under any scenario without using Aliso Canyon and/or resorting to curtailments. Furthermore, in some scenarios, 1-in-10 peak demand could not have been met even with the 869 MMcfd in withdrawal capacity available at Aliso Canyon at the 24.6 Bcfd inventory cap.[17] If electric generators were curtailed to minimum generation on peak days, these shortfalls could be reduced but not eliminated. Under the Cold Forecast assumptions, the shortfall would have been roughly 900 MMcfd in February, even with electric generators curtailed to minimum generation.

Given the precarious state of the SoCalGas system, Southern California was fortunate to have experienced extremely mild temperatures for most of winter 2017-18, with sustained cold weather hitting only late in the season. However, hoping for continued mild weather is not a prudent strategy for ensuring future energy reliability. Pipeline capacity has not improved appreciably since winter 2017-18, and there is a chance that it could deteriorate further. When Line 235-2 ruptured in October 2017, there was insufficient time to substantially increase storage inventory before the high-demand winter season began. However, there is time now to boost storage inventory in advance of the 2018-19 winter season. Doing so requires increasing the cap on Aliso inventory while there is still time to inject gas into storage.

Public Utilities Code Section 715 also requires the CPUC to consider the impact of Aliso inventory on rates. While the CPUC has not completed its planned analysis of winter 2017-18, it is clear that the combination of pipeline outages and limits on Aliso storage led to continuing pressure on SoCalGas citygate commodity prices. Natural gas prices spiked repeatedly on cold days in the SoCalGas service territory, while PG&E citygate prices remained flat *(see Figure 1, below)*.

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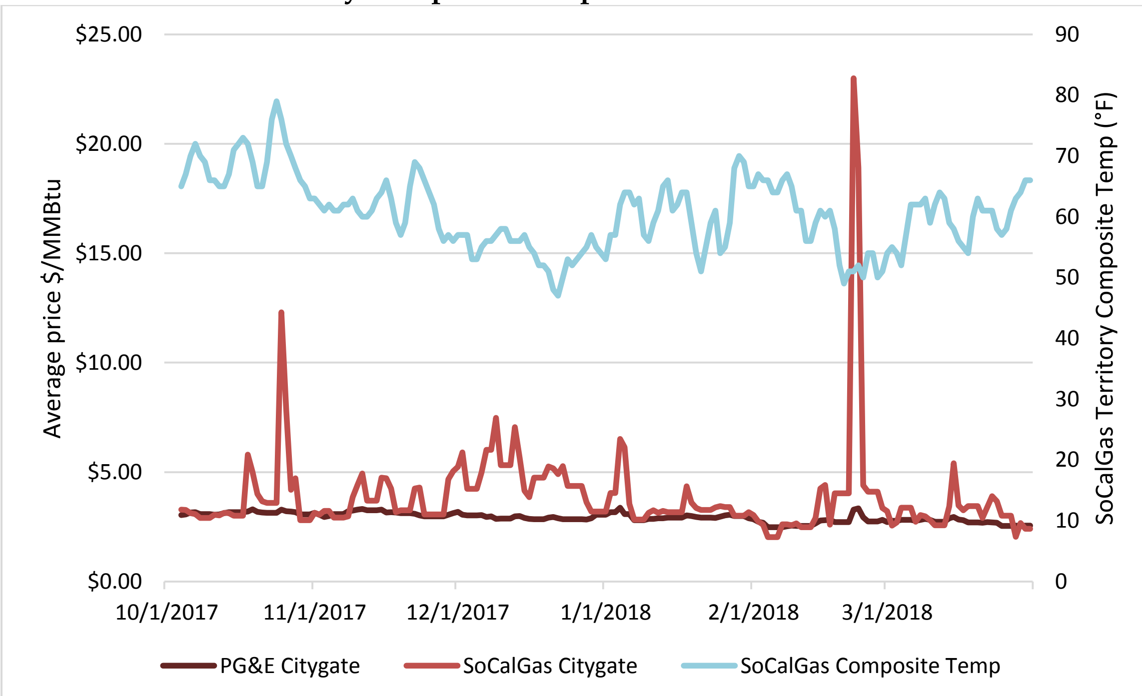
[16] The assumptions used in the Winter 2017-18Technical Assessment (Table 2, page 9) were based on hydraulic modeling done for the Winter 2016 Technical Assessment (Table 1, p. 19). The additional pipeline outages were subtracted from the total supported demand on a one-for-one basis. In Table 3, Total Pipeline Capacity for January-March was revised downward by 30 MMcfd compared to the 2017-18 Winter Technical Assessment due to events that occurred after the Technical Assessment was published. Line 4000 was expected to return to service at a capacity of 350 MMcfd. However, it actually returned to service at 270 MMcfd. That 80 MMcfd loss was somewhat offset by the resultant ability to bring in 50 MMcfd of interruptible supply at Kramer Junction.

[17] Advice Letter 5275-A (April 20, 2018) states that at 24.6 Bcf in inventory, Aliso Canyon has a projected withdrawal rate of 869 MMcfd.

Figure 1: Comparison of SoCalGas and PG&E Citygate Prices and SoCalGas Service Territory Composite Temperature: 10/3/17-3/31/18[18]



Findings

This report recommends that the maximum allowable working gas at the Aliso Canyon gas storage field should be increased to 34 Bcf. The minimum should remain 0 Bcf or the level that a prudent operator would maintain in order to preserve the integrity of the field. This minimum level is in keeping with the minimum established by DOGGR and the language of the previous version of the 715 Report.[19]

Several factors have led to the recommendation to increase the cap on Aliso inventory. First, significant pipeline outages have made it more difficult for customers to deliver enough gas to meet their demand, increasing reliance on storage. Second, experience this past winter caused Energy Division to explicitly consider the impact that declines in inventory at the non-Aliso storage fields have on their withdrawal capacity. Third, the experience of winter 2017-18 also caused Energy Division to examine whether the SoCalGas system has the ability to support monthly 1-in-10 peak day demand throughout the winter rather than determining the amount of Aliso inventory needed to meet one peak day. Finally, without Aliso, systemwide injection capacity is limited, which makes it difficult to inject gas into all the storage fields.

It is important to note that the pipeline outages currently in effect are not expected to be permanent. Additional mitigation measures proposed in the Summer 2018 Technical Assessment, such as deliveries of liquefied natural gas and changes to the gas tariffs,

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[18] Based on weighted average spot prices reported by PointLogic; composite temperature data from Envoy.
[19] December 11, 2017, 715 Report, p. 2.

could also change the reliability equation in the future. However, the impact of the proposed additional mitigation measures is uncertain and will likely be insufficient to fully eliminate the identified shortfalls. Energy Division will revisit the recommendations of this report as the impact of these measures becomes more certain.

Pipeline Outages

Energy Division created four gas balances for this report to estimate inventory levels under different pipeline capacity and weather scenarios.[20] Gas balances look at average daily demand by month rather than peak demand and provide a means of forecasting how storage may be drawn down throughout the winter. Gas Balances A-average and A-cold assume that Line 4000 remains at its current reduced capacity all winter and that an additional 180 MMcfd of pipeline capacity is lost in September. In contrast, Gas Balances B-average and B-cold assume that Line 4000 returns to its maximum capacity of 740 MMcfd in September and there are no additional pipeline outages. Gas Balances A-average and B-average are based on demand assumptions for an average temperature year, while A-cold and B-cold assume an average summer and a cold winter.[21]

Table 4 below forecasts the amount of pipeline capacity that may be available this winter. It is modeled on Table 2 in the Winter 2017-18 Technical Assessment. It differs from that table in that it includes the 30 MMcfd of incremental pipeline capacity on Line 2000 that was lost in March 2018 due the expiration of a right-of-way agreement between SoCalGas and the Morongo Band of Mission Indians. It has also been modified to include the assumptions about pipeline capacity used in Gas Balances A and B.

Table 4: Forecasted Pipeline Capacity Under Scenarios A and B

(MMcfd)	Scenario A	Scenario B
Supported Gas Demand from Table 1 of the 2016 Winter Assessment (Includes both pipeline and withdrawal capacity)	4,567	4,567
Static Withdrawal Capacity	(1,181)	(1,181)
Combined Outages Lines 4000/235-2	(530)	(60)
Reductions at Ehrenberg (Lines 2000 and 5000)	(410)	(230)
Total Pipeline Capacity: No Mitigation	2,446	3,096
Mitigation 1: Otay Mesa	200	200
Mitigation 2: Kramer Junction (Interruptible)	50	0
Total Pipeline Capacity	2,696	3,296

[20] The gas balances and a summary of the assumptions used are provided in Appendix A.

[21] Demand assumptions are from SoCalGas' workpapers for the 2016 California Gas Report, pp. 12-13 and 25-26.

Impact of the Decline in Inventory on Withdrawal Capacity

The Gas Balances in Appendix A use the assumptions about pipeline capacity shown in Table 4 above to determine whether average monthly demand can be supported all winter long. They also provide a forecast of how much inventory will be left in the non-Aliso fields at the end of every month.[22] The resulting month-end inventory levels for the non-Aliso fields are used in Tables 5 and 6 below to provide a range of possible inventory and withdrawal capacity scenarios.

Table 5: Non-Aliso Month-End Inventory in 2018-19 Gas Balances (Bcf)

Gas Balance	November	December	January	February	March
A-average	37	29	20	15	13
A-cold	38	25	13	5	3
B-average	50	44	36	31	38
B-cold	50	38	29	25	26

Table 6: Estimated Non-Aliso Withdrawal Capacity at Month-End Inventory Levels in 2018-19 Gas Balances (MMcfd)[23]

	November	December	January	February	March
A-average	1,064	1,040	914	813	761
A-cold	1,064	996	803	584	532
B-average	1,113	1,097	1,064	1,048	1,080
B-cold	1,113	1,080	1,040	1,032	1,032

Table 5 shows that inventory at the non-Aliso fields declines precipitously in the A Scenarios, falling to 3 Bcf in March of the A-cold Scenario. Table 6 shows the impact that declining inventory has on withdrawal capacity. In the A Scenarios, there is little non-Aliso withdrawal capacity left in February and March, leaving the gas system very vulnerable to cold weather, outages, or any disruption in flowing supply.[24]

Ability to Support Monthly 1-in-10 Year Peak Day Demand throughout the Winter

Table 7 below combines the forecasted pipeline capacity from Table 4 with the estimated withdrawal capacities from Table 6 to evaluate whether monthly 1-in-10 peak day demand can be met under the different scenarios.

[22] See the row labeled "OTF Month-End Storage Inventory (Bcf)." OTF stands for "other three fields."

[23] The combined withdrawal capacities were calculated using estimated withdrawal curves as of June 1, 2018. The withdrawal curves were provided to Energy Division by SoCalGas on May 14, 2018.

[24] SoCalGas is unlikely to let inventories fall as low as shown in the A Scenarios. Noncore customers would likely experience preemptive curtailments long before inventories reached such low levels.

Table 7: Ability to Meet 2018-19 Winter Monthly 1-in-10 Peak Day Forecast[25] with Estimated Month-End Non-Aliso Withdrawal Capacity (MMcfd)

Gas Balance	(a) 1-in-10 Peak Day Demand	(b) Total Pipeline Capacity	(c) Estimated Withdrawal Capacity	(d) Total System Capacity (d=b+c)	(e) Surplus/ Shortfall (e=d-a)
November					
A-average	4,247	2,696	1,064	3,760	-487
A-cold	4,247	2,696	1,064	3,760	-487
B-average	4,247	3,296	1,113	4,409	162
B-cold	4,247	3,296	1,113	4,409	162
December					
A-average	4,936	2,696	1,040	3,736	-1,200
A-cold	4,936	2,696	996	3,692	-1,244
B-average	4,936	3,296	1,097	4,393	-543
B-cold	4,936	3,296	1,080	4,376	-560
January					
A-average	4,936	2,696	914	3,610	-1,326
A-cold	4,936	2,696	803	3,499	-1,437
B-average	4,936	3,296	1,064	4,360	-576
B-cold	4,936	3,296	1,040	4,336	-600
February					
A-average	4,622	2,696	813	3,509	-1,113
A-cold	4,622	2,696	584	3,280	-1,342
B-average	4,622	3,296	1,048	4,344	-278
B-cold	4,622	3,296	1,032	4,328	-294
March					
A-average	4,410	2,696	761	3,457	-953
A-cold	4,410	2,696	532	3,228	-1,182
B-average	4,410	3,296	1,080	4,376	-34
B-cold	4,410	3,296	1,032	4,328	-82

In Table 7, the shortfalls displayed in column (e) represent the amount of gas from Aliso and/or curtailments that would be required if a 1-in-10 day occurs and the pipeline capacity and weather scenarios assumed in the Gas Balances come to fruition. The need for Aliso's withdrawal capacity is greatest under Scenarios A-average and A-cold. The greatest shortfall is seen in January under Scenario A-cold, when an additional 1,437 MMcfd is required to meet peak demand. In this scenario, the potential for large

[25] Winter 2017-18 peak day forecasts were created for the 2016 California Gas Report. The 2018 California Gas Report is expected to be published in July and will include updated forecasts.

shortfalls continues through March, when an additional 1,182 MMcfd would be required on a 1-in-10 peak day. Aliso's maximum withdrawal capacity when filled to the maximum safe inventory of 68.6 Bcf determined by DOGGR is estimated to be 1,092 MMcfd.[26] Therefore, these shortfalls could not be met without curtailments at any authorized level of Aliso inventory. However, the depth of the curtailments could be reduced if Aliso inventory was higher than the 24.6 Bcf authorized in the December 11, 2017, version of the 715 Report.[27]

The situation is much less dire in Scenarios B-average and B-cold. The largest shortfall is seen in January in Scenario B-cold, when an additional 600 MMcfd is required. The shortfalls drop significantly in February and March — in Scenario B-cold the March shortfall is only 82 MMcfd.

To further complicate matters, it is very difficult to fill Aliso under the A Scenarios because of the critical lack of pipeline capacity. In Gas Balances A-average and A-cold, the maximum achievable Aliso inventory is 31 Bcf, a level of inventory that provides under 1,000 MMcfd of withdrawal capacity.[28] In short, under conditions when Aliso inventory would be most needed, it is least likely to be available.

Unfortunately, there is not time to wait and see which set of assumptions most closely matches reality because of the need to inject gas into storage early in the summer. In the A Gas Balances, the largest build in storage inventory takes place in early in summer, when demand is relatively low and there are no additional pipeline outages. Waiting until late summer to determine the maximum Aliso inventory would mean missing this window for injection.

In the A Scenarios, Aliso withdrawals would be needed over multiple months, reducing the field's inventory level and withdrawal capacity. In the A-average scenario, there is 10 Bcf left at Aliso in March; in A-cold there is only 1 Bcf. Confidentiality concerns preclude Energy Division from revealing Aliso withdrawal capacity at all the inventory levels of concern in this report. However, Table 8 includes information that SoCalGas has stated publicly to provide a rough idea of how declines in Aliso inventory impact withdrawal capacity.

[26] This estimate is untested since the field has not been filled to 68.6 Bcf since the switch to tubing-only flow.
[27] The California ISO and LADWP have not yet calculated what their minimum generation requirements will be for winter 2018-19. Using their estimates for February 2018 as a proxy, peak day demand can be reduced by roughly 592 MMcfd if electric generators are curtailed to minimum generation. See Table 7 on p. 15 of the Winter 2017-18 Technical Assessment.
[28] SoCalGas has stated that withdrawal capacity for individual fields is market sensitive and therefore confidential. This report only includes specific withdrawal capacities that have been previously made public or that SoCalGas has agreed to disclose

Table 8: Estimated Aliso Withdrawal Capacity at Four Inventory Levels[29]

Inventory (Bcf)	Withdrawal Capacity (MMcfd)
12.3	574
21.9	815
24.6	869
68.6	1,092

Injection Capacity

With the Aliso Canyon Turbine Replacement Project fully operational, Aliso injection capacity is estimated to be 545 MMcfd. In contrast, non-Aliso injection capacity in mid-May was roughly 230 MMcfd.[30] The injection capacity at Aliso therefore represents over 70 percent of effectively available systemwide injection capacity.[31]

Injection capacity serves two important purposes, and the total available injection capacity must be divided between these two purposes. First, it provides firm injection rights that customers can purchase in order to inject gas into storage. Second, a portion of total injection capacity is set aside to help the gas system stay in balance. On days when customers schedule more gas onto the system than is burned, something must be done with the excess gas to keep the pipelines from exceeding their maximum allowable operating pressure. If injection capacity is available, the SoCalGas System Operator can balance the system by injecting the extra gas into storage. If there is not enough injection capacity available, the System Operator must either call a High Operational Flow Order (OFO)[32] or turn away gas at the border to avoid over-pressurization. Both of these measures increase customer costs and create disincentives for customers seeking to take advantage of unpredictable releases of injection capacity late in the day.

[29] Estimates for the first three rows are taken from Table 2 of Advice Letter 5275-A and p. 7 of Attachment C to AL 5275-A. SoCalGas authorized the CPUC to disclose the withdrawal capacity at 68.6 Bcf in a June 6, 2018, email. All estimates are based on the number of wells expected to be in service at the beginning of summer 2018.

[30] On May 11, 2018, Envoy reported injection capacity of 236,000 dekatherms (Dth): https://scgenvoy.sempra.com/#nav=/Public/ViewExternalOFO.getOFO%3Frand%3D40. Using the conversion factor of 1027.348 Dth/MMcf provided by SoCalGas, that is equivalent to 229.7 MMcf (236,000 Dth/1,027.348 Dth/MMcf = 229.7 MMcf).

[31] In a May 15, 2018, announcement regarding the Aliso Canyon Turbine Replacement Project, SoCalGas states that it has 995 MMcfd in total injection capacity. The effectively available total is much lower, however, due to long-term reductions in injection capacity at Honor Rancho and La Goleta that are not expected to be remedied in the timeframe covered by this report.

[32] A High OFO is called when too much gas is scheduled onto the system and there is a danger that pipelines could exceed their maximum allowable operating pressure. On a High OFO day, gas customers face a financial penalty if they deliver more than 105 percent of their gas burn. The System Operator will not allow more gas onto the system than the pipelines are designed to handle. If there is still too much gas scheduled after a High OFO is called, the System Operator will simply refuse to accept additional gas from the interstate pipelines.

When Aliso reaches its maximum inventory, its injection capacity is no longer available. This leads to a significant drop in the injection capacity available for both firm injection rights and balancing. The end result of having less injection capacity for balancing services is that less gas will be scheduled into the system to fill the non-Aliso storage facilities since the injection capacity in those facilities may need to be held in reserve to mitigate overdeliveries. Limits on firm injection rights mean customers cannot enter into long-term contracts to purchase the extra gas they need to inject into storage. The reduction in storage set aside for balancing leads to an increase in OFOs and incidences of gas being turned away, which make customers wary of overscheduling. Therefore, one of the factors in the recommendation to increase the maximum Aliso inventory is the need to extend the period during which Aliso's injection capacity is available.

Recommendations

Given the uncertainty regarding the pipeline capacity that will be available this winter along with concerns about maintaining injection and withdrawal capacity, this report recommends a maximum Aliso inventory of 34 Bcf. While this level of inventory does not provide a substantially higher withdrawal capacity than the 31 Bcf that is shown as the maximum achievable inventory in the A Gas Balances, it does allow the system to maintain relatively high injection and withdrawal capacity over a longer period. This is important even if pipeline capacity increases to the level forecasted in the B Scenarios.

Aliso is not needed to meet average daily demand in Gas Balance B-average. However, in Gas Balance B-cold, 22 Bcf from Aliso is used.[33] Table 9 below compares how Aliso inventory would be impacted if the Aliso draw-down followed the pattern shown in Gas Balances A-cold and B-cold but Aliso was capped at either 24.6 or 34 Bcf.[34]

Table 9: Comparison of Aliso Draw-Down under Scenarios A-cold and B-cold at Caps of 24.6 and 34 Bcf

	November	December	January	February	March
A-cold					
24.6 Cap	24.6	12.6	0.6	0.0	0.0
34 Cap	34	22	10	4	4
B-cold					
24.6 Cap	24.6	19.6	11.6	2.6	2.6
34 Cap	34	29	21	12	12

At the 24.6 Bcf cap, there is not enough gas in Aliso to meet January peak demand under either the A-cold or the B-cold Scenario. With a cap of 34 Bcf, the January peak cannot be met in the A-cold Scenario, but it can be met under B-cold assumptions. Raising the cap

[33] Usage to meet average demand is in addition to the gas from Aliso needed to meet peak day demand.

[34] As noted in Appendix A, the Gas Balances do not impose a cap on Aliso inventory. Only physical constraints on storage injections were considered.

thus provides an additional margin of reliability should either the more pessimistic pipeline or weather scenarios come to pass.

If pipeline outages continue, it may not be possible to fill Aliso to 34 Bcf. However, under certain weather and pipeline conditions it may be achievable. Given the potential for reliability problems this winter, this report finds it prudent to recommend a maximum level that would bring Southern California closer to being able to meet 1-in-10 peak day demand over a longer period. It is important to emphasize, however, that even with 34 Bcf at Aliso, the SoCalGas system would not meet the 1-in-10 design standard with the pipeline outages assumed in the A Scenarios. Southern California would remain vulnerable to disruptions in energy supply that could lead to curtailments of noncore customers, including electric generators.

Statutorily Required Determinations

Consistent with SB 380, the CPUC has a statutory requirement to make four determinations concerning the Aliso Canyon storage facility prior to the approval of injections. These determinations are presented below.

1. *The range of working gas necessary at the Aliso Canyon storage facility to ensure safety and reliability at just and reasonable rates in California.*

This report finds that 34 Bcf of inventory at the Aliso Canyon natural gas storage field is necessary to maintain reliability given forecasted demand and supply constraints and may be practically achievable before the start of the 2018-19 winter season. If Line 4000 returns to full capacity before winter and no additional outages are sustained, this level of inventory should be sufficient. If Line 4000 remains at reduced capacity and additional pipeline capacity is lost, Southern California will face risks to reliability even with the increased inventory at Aliso. Despite these risks, Energy Division does not recommend authorizing a higher level of Aliso inventory because it is unlikely that the storage field could be filled above 34 Bcf under the more pessimistic pipeline scenarios.

Minimum Aliso inventory remains at 0 Bcf or the level that a prudent operator would maintain in order to preserve the integrity of the field This minimum determination is in keeping with the minimum established by DOGGR and the language of the previous version of the 715 Report.

2. *The amount of natural gas production at the facility needed to meet safety and reliability requirements.*

To meet peak day demand in a scenario where Line 4000 remains at reduced capacity and an additional 180 MMcfd of pipeline capacity is lost, 1,437 MMcfd of Aliso natural gas production is required. This is not achievable at any inventory with the number of wells that are expected to be in service by June 1, 2018.

To meet peak day demand in a scenario where Line 4000 returns to service and there are no additional pipeline outages, 600 MMcfd in Aliso withdrawal capacity is required.

3. *The number of wells and associated injection and production capacity required.*

As of May 31, 2018, 46 wells had completed all testing and remediation requirements and were operational. Up to eight more wells may be in service before the end of summer, which will provide a modest increase in Aliso's production capacity. These wells are sufficient to meet peak demand in the more optimistic pipeline capacity scenario but not in the more pessimistic scenario.

SoCalGas has provided a range of historical withdrawal capacities for the 22 wells that have not yet returned to service but are not slated to be plugged and abandoned. If all the wells were to perform at the minimum of the range, there still would not be enough withdrawal capacity to meet peak demand in the pessimistic pipeline scenario. If all the wells were to perform at the maximum of that range, it is possible that peak demand of 1,437 MMcfd could be met, depending on the pressure in the field. It should be noted that this finding is based on simple addition using historical data and does not take into account factors such as the switch to tubing-only flow. In the event that a significant number of new wells return to service, a new Aliso withdrawal curve should be created to better estimate maximum withdrawal capacity.

The Aliso Canyon Turbine Replacement project is currently being brought online and should soon be fully operational. When the new electric compressors are operating at full capacity, Aliso is expected to have a maximum injection capacity of 545 MMcfd. This represents over 70 percent of effectively available systemwide injection capacity.[35]

4. *The availability of sufficient natural gas production wells that have satisfactorily completed required testing and remediation.*

As of May 31, 2018, 46 wells had completed all testing and remediation requirements and were operational. Up to eight more wells may be in service before the end of summer, which will provide a modest increase in Aliso's production capacity.

[35] In a May 15, 2018, announcement regarding the Aliso Canyon Turbine Replacement Project, SoCalGas states that it has 995 MMcfd in total injection capacity. The effectively available total is much lower, however, due to long-term reductions in injection capacity at Honor Rancho and La Goleta that are not expected to be remedied in the timeframe covered by this report.

Appendix A

Gas Balances

Energy Division created four gas balances for this report to estimate inventory levels under different weather and pipeline scenarios. These gas balances do not project what will actually happen but rather show what would happen if the supply, demand, and storage assumptions shown come to pass. These gas balances are similar to those created for the 2018 Summer Technical Assessment but contain some updates based on what has actually happened in April and May. For example, actual storage inventory at the end of April was lower than projected in the Technical Assessment, and low demand caused SoCalGas to reduce Southern System pipeline capacity to 700 MMcfd for most of May.

The four gas balances also combine some of the assumptions in the different gas balances created for the 2018 Summer Technical Assessment. In the case of Otay Mesa, 30 MMcfd is assumed through October, while 200 MMcfd is assumed throughout the November-March winter season. In all cases, no limits are put on Aliso inventory beyond the physical limits imposed by DOGGR and the existing constraints on injecting gas into storage. This was done in order to understand what is physically possible under different assumptions. However, withdrawals were made from the non-Aliso fields first where possible.

Gas Balances A-average and A-cold share the same pipeline assumptions but look at different weather scenarios. Gas Balance A-average estimates what would happen in an average temperature year, while Gas Balance A-cold assumes an average summer and a cold winter. Both gas balances assume that Line 4000 remains at its current capacity of 270 MMcfd all winter long and that Kramer Junction is able to deliver 600 MMcfd. They also assume that an additional 180 MMcfd of pipeline capacity is lost in September. In Gas Balance A-cold, by the end of the winter season there is insufficient gas in storage to maintain a positive deliverability balance, even on an average day. Furthermore, in both A Gas Balances, the maximum level of achievable Aliso inventory is 31 Bcf.

Gas Balances B-average and B-cold also look at an average temperature year and an average summer/cold winter year respectively. These gas balances assume that Line 4000 returns to full capacity of 740 MMcfd in September, which reduces Kramer Junction's capacity to 550 MMcfd. Both gas balances assume that there are no additional pipeline outages throughout the winter.

Ideally, a gas balance would result in a reserve margin of 15 percent. In these gas balances, a 15 percent reserve margin was only possible for a few months in the more optimistic B-average and B-cold scenarios.

Gas Balance A-average

SoCalGas Month-End Gas Balance, May 2018-March 2019: Average Temperature Year												
CGR Demand (MMcfd)		**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core		751	692	630	608	628	714	1,072	1,483	1,420	1,379	1,143
Noncore including EG		1,063	1,089	1,362	1,408	1,526	1,270	1,100	1,136	1,151	1,112	1,031
Wholesale & International		358	377	374	374	392	391	422	521	501	486	414
Co. Use and LUAF		27	27	30	30	32	30	33	40	39	38	33
Subtotal Demand		2,199	2,185	2,396	2,420	2,578	2,405	2,627	3,180	3,111	3,015	2,621
Storage Injection (Other Three Fields)		130	220	85	60	0	0	0	0	0	0	0
Storage Injection (Aliso)		0	140	85	60	0	0	0	0	0	0	0
Storage Injection Total		130	360	170	120	0	0	0	0	0	0	0
System Total Throughput		2,329	2,545	2,566	2,540	2,578	2,405	2,627	3,180	3,111	3,015	2,621
Supply (MMcfd)												
California Line 85 Zone		60	60	60	60	60	60	60	60	60	60	60
Wheeler Ridge Zone		765	765	765	765	765	765	765	765	765	765	765
Blythe (Ehrenberg) into Southern Zone		700	980	980	980	800	800	800	800	800	800	800
Otay Mesa into Southern Zone		0	30	30	30	30	30	200	200	200	200	200
Kramer Junction into Northern Zone		600	600	600	600	600	600	600	600	600	600	600
North Needles into Northern Zone		270	270	270	270	270	270	270	270	270	270	270
Topock into Northern Zone		0	0	0	0	0	0	0	0	0	0	0
Sub Total Pipeline Receipts		2,395	2,705	2,705	2,705	2,525	2,525	2,695	2,695	2,695	2,695	2,695
Storage Withdrawal (Other Three Fields)		0	0	0	0	100	0	110	275	275	200	50
Storage Withdrawal (Aliso)		0	0	0	0	0	0	0	275	250	150	0
Total Supply		2,395	2,705	2,705	2,705	2,625	2,525	2,805	3,245	3,220	3,045	2,745
DELIVERABILITY BALANCE (MMcfd)		66	160	139	165	47	120	178	65	109	30	124
Reserve Margin		3%	6%	5%	6%	2%	5%	7%	2%	4%	1%	5%
OTF Month-End Storage Inventory (Bcf)	28.4	32	39	42	44	41	41	37	29	20	15	13
Aliso Month-End Storage Inventory (Bcf)	22.2	22	26	29	31	31	31	31	22	15	10	10
Total Storage Inventory	50.6	55	65	71	74	71	71	68	51	35	25	23

Gas Balance A-cold

SoCalGas Month-End Gas Balance, May 2018-March 2019: Average Summer / Cold Winter

CGR Demand (MMcfd)		**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core		751	692	630	608	628	714	1,183	1,696	1,619	1,559	1,274
Noncore including EG		1,063	1,089	1,362	1,408	1,526	1,270	1,150	1,188	1,218	1,159	1,061
Wholesale & International		358	377	374	374	392	391	453	577	560	551	451
Co. Use and LUAF		27	27	30	30	32	30	35	44	43	41	35
Subtotal Demand		2,199	2,185	2,396	2,420	2,578	2,405	2,821	3,505	3,440	3,310	2,821
Storage Injection (Other Three Fields)		130	230	85	80	0	0	0	0	0	0	0
Storage Injection (Aliso)		0	150	85	70	0	0	0	0	0	0	0
Storage Injection Total		130	380	170	150	0	0	0	0	0	0	0
System Total Throughput		2,329	2,565	2,566	2,570	2,578	2,405	2,821	3,505	3,440	3,310	2,821
Supply (MMcfd)												
California Line 85 Zone		60	60	60	60	60	60	60	60	60	60	60
Wheeler Ridge Zone		765	765	765	765	765	765	765	765	765	765	765
Blythe (Ehrenberg) into Southern Zone		700	980	980	980	800	800	800	800	800	800	800
Otay Mesa into Southern Zone		0	30	30	30	30	30	200	200	200	200	200
Kramer Junction into Northern Zone		600	600	600	600	600	600	600	600	600	600	600
North Needles into Northern Zone		270	270	270	270	270	270	270	270	270	270	270
Topock into Northern Zone		0	0	0	0	0	0	0	0	0	0	0
Sub Total Pipeline Receipts		2,395	2,705	2,705	2,705	2,525	2,525	2,695	2,695	2,695	2,695	2,695
Storage Withdrawal (Other Three Fields)		0	0	0	0	100	0	125	410	375	300	75
Storage Withdrawal (Aliso)		0	0	0	0	0	0	15	400	375	200	20
Total Supply		2,395	2,705	2,705	2,705	2,625	2,525	2,835	3,505	3,445	3,195	2,790
DELIVERABILITY BALANCE (MMcfd)		66	140	139	135	47	120	14	0	5	-115	-31
Reserve Margin		3%	5%	5%	5%	2%	5%	0%	0%	0%	-3%	-1%
OTF Month-End Storage Inventory (Bcf)	28.4	32	39	42	44	41	41	38	25	13	5	3
Aliso Month-End Storage Inventory (Bcf)	22.2	22	27	29	31	31	31	31	19	7	1	1
Total Storage Inventory	50.6	55	66	71	76	73	73	69	44	20	6	3

Gas Balance B-average

SoCalGas Month-End Gas Balance, May 2018-March 2019: Average Temperature Year												
CGR Demand (MMcfd)		**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core		751	692	630	608	628	714	1,072	1,483	1,420	1,379	1,143
Noncore including EG		1,063	1,089	1,362	1,408	1,526	1,270	1,100	1,136	1,151	1,112	1,031
Wholesale & International		358	377	374	374	392	391	422	521	501	486	414
Co. Use and LUAF		27	27	30	30	32	30	33	40	39	38	33
Subtotal Demand		2,199	2,185	2,396	2,420	2,578	2,405	2,627	3,180	3,111	3,015	2,621
Storage Injection (Other Three Fields)		130	220	85	60	150	75	0	0	0	0	230
Storage Injection (Aliso)		0	140	85	60	150	400	400	0	0	0	0
Storage Injection Total		130	360	170	120	300	475	400	0	0	0	230
System Total Throughput		2,329	2,545	2,566	2,540	2,878	2,880	3,027	3,180	3,111	3,015	2,851
Supply (MMcfd)												
California Line 85 Zone		60	60	60	60	60	60	60	60	60	60	60
Wheeler Ridge Zone		765	765	765	765	765	765	765	765	765	765	765
Blythe (Ehrenberg) into Southern Zone		700	980	980	980	980	980	980	980	980	980	980
Otay Mesa into Southern Zone		0	30	30	30	30	30	200	200	200	200	200
Kramer Junction into Northern Zone		600	600	600	600	550	550	550	550	550	550	550
North Needles into Northern Zone		270	270	270	270	740	740	740	740	740	740	740
Topock into Northern Zone		0	0	0	0	0	0	0	0	0	0	0
Sub Total Pipeline Receipts		2,395	2,705	2,705	2,705	3,125	3,125	3,295	3,295	3,295	3,295	3,295
Storage Withdrawal (Other Three Fields)		0	0	0	0	0	0	0	200	275	175	0
Storage Withdrawal (Aliso)		0	0	0	0	0	0	0	0	0	0	0
Total Supply		2,395	2,705	2,705	2,705	3,125	3,125	3,295	3,495	3,570	3,470	3,295
DELIVERABILITY BALANCE (MMcfd)		66	160	139	165	247	245	268	315	459	455	444
Reserve Margin		3%	6%	5%	6%	9%	9%	9%	10%	15%	15%	16%
OTF Month-End Storage Inventory (Bcf)	28.4	32	39	42	44	48	50	50	44	36	31	38
Aliso Month-End Storage Inventory (Bcf)	22.2	22	26	29	31	35	48	60	60	60	60	60
Total Storage Inventory	50.6	55	65	71	74	83	98	110	104	95	90	98

Gas Balance B-cold

SoCalGas Month-End Gas Balance, May 2018-March 2019: Average Summer / Cold Winter												
CGR Demand (MMcfd)		**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Core		751	692	630	608	628	714	1,183	1,696	1,619	1,559	1,274
Noncore including EG		1,063	1,089	1,362	1,408	1,526	1,270	1,150	1,188	1,218	1,159	1,061
Wholesale & International		358	377	374	374	392	391	453	577	560	551	451
Co. Use and LUAF		27	27	30	30	32	30	35	44	43	41	35
Subtotal Demand		2,199	2,185	2,396	2,420	2,578	2,405	2,821	3,505	3,440	3,310	2,821
Storage Injection (Other Three Fields)		130	230	85	80	160	40	0	0	0	0	50
Storage Injection (Aliso)		0	150	85	70	50	300	50	0	0	0	0
Storage Injection Total		130	380	170	150	210	340	50	0	0	0	50
System Total Throughput		2,329	2,565	2,566	2,570	2,788	2,745	2,871	3,505	3,440	3,310	2,871
Supply (MMcfd)												
California Line 85 Zone		60	60	60	60	60	60	60	60	60	60	60
Wheeler Ridge Zone		765	765	765	765	765	765	765	765	765	765	765
Blythe (Ehrenberg) into Southern Zone		700	980	980	980	980	980	980	980	980	980	980
Otay Mesa into Southern Zone		0	30	30	30	30	30	200	200	200	200	200
Kramer Junction into Northern Zone		600	600	600	600	550	550	550	550	550	550	550
North Needles into Northern Zone		270	270	270	270	740	740	740	740	740	740	740
Topock into Northern Zone		0	0	0	0	0	0	0	0	0	0	0
Sub Total Pipeline Receipts		2,395	2,705	2,705	2,705	3,125	3,125	3,295	3,295	3,295	3,295	3,295
Storage Withdrawal (Other Three Fields)		0	0	0	0	0	0	0	400	300	150	0
Storage Withdrawal (Aliso)		0	0	0	0	0	0	0	150	250	350	0
Total Supply		2,395	2,705	2,705	2,705	3,125	3,125	3,295	3,845	3,845	3,795	3,295
DELIVERABILITY BALANCE (MMcfd)		66	140	139	135	337	380	424	340	405	485	424
Reserve Margin		3%	5%	5%	5%	12%	14%	15%	10%	12%	15%	15%
OTF Month-End Storage Inventory (Bcf)	28.4	32	39	42	44	49	50	50	38	29	25	26
Aliso Month-End Storage Inventory (Bcf)	22.2	22	27	29	31	33	42	44	39	31	22	22
Total Storage Inventory	50.6	55	66	71	76	82	93	94	77	60	46	48