Winter 2021-22 Southern California Reliability Assessment

BY CALIFORNIA PUBLIC UTILITIES COMMISSION STAFF

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Contents

Table of Figures

Executive Summary

The Southern California Gas Company (SoCalGas) gas system approaches this winter at some risk for reliability issues, especially in the Southern Zone, and at elevated risk for price volatility compared to last year despite some positive trends. In-state, conditions are better than in fall 2020: overall SoCalGas pipeline capacity is significantly higher and the combined gas storage fields were 96 percent full on September 30. The weather forecast for Southern California offers a mixed bag for gas prices and reliability. Temperatures are expected to be warmer than average, which reduces gas demand, but also drier, which could reduce local hydroelectric capacity.[1] Outside California, both national and international gas prices are higher than in recent years, creating a higher baseline for in-state gas prices. Most concerning, however, is an outage on an El Paso interstate pipeline (El Paso outage)[2] caused by an August 15, 2021, rupture in Coolidge, Arizona. This outage reduces the amount of gas flowing west to California from the Permian Basin and poses localized risks to the southern part of the SoCalGas system.

To estimate winter risk, California Public Utilities Commission (CPUC) staff (staff) modeled supply and demand under several different weather and pipeline scenarios. In all scenarios, *average* daily demand is met throughout the winter. However, in the worst-case scenario, which assumes that the weather is cold and dry and the El Paso pipeline outage lasts all winter, storage is significantly drawn down by the end of the season.

When storage inventories are low, the amount of gas that can be withdrawn from storage also declines, making it more difficult to meet demand on cold days late in the season. If the coldest day in 10 years were to occur between January and March under the worst-case conditions, SoCalGas would be unable to meet all customer demand. In the best-case scenario, which assumes an average weather winter with the El Paso interstate pipeline back in service by December 1, SoCalGas would be able to meet all customer demand on a 1-in-10 peak day.

Service to most core—or residential and small business—customers is not expected to be at risk under current conditions. However, the El Paso outage creates uncertainty regarding gas supplies to SoCalGas' Southern Zone, which serves San Diego, Riverside, and Imperial counties. Curtailments, or shut-offs, of customers in the Southern Zone could occur this winter if the

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[1] National Oceanic and Atmospheric Administration, "U.S. Winter Outlook: Drier, warmer South, wetter North with Return of La Niña," October 21, 2021: U.S. Winter Outlook: Drier, warmer South, wetter North with return of La Nina | National Oceanic and Atmospheric Administration (noaa.gov).

[2] The federal Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a corrective action order on August 19, 2021, which required the pipeline operator to reduce the pressure on the entire affected pipeline by 20 percent: PHMSA Corrective Action Order to El Paso Natural Gas Company | PHMSA (dot.gov). The operator, El Paso Natural Gas (EPNG), subsequently posted a force majeure notice stating: "EPNG remains under a reduced operating pressure on the entire Line 2000 system, which in effect removes the Line 2000 system from service from Black River compressor station [in Texas] to the California border." Informational Postings :: EL PASO NATURAL GAS CO. L.L.C. (kindermorgan.com).

region experiences a very cold day and the El Paso pipeline is not repaired. When demand cannot be met, SoCalGas implements its curtailment process, which begins with noncore electric generation customers and proceeds to noncore, non-electric generation and then core customers as laid out in SoCalGas Tariff Rule 23.[3]

Staff authored this report and shared it with the California Energy Commission, the California Independent System Operator, and the Los Angeles Department of Water and Power (Joint Agencies) for review and comment. CPUC staff, however, are responsible for the final content of this assessment. Should conditions significantly change, the CPUC will issue monthly supplemental reports this winter with input from the Joint Agencies to provide updates and revised gas balance analyses reflecting the new information.

Summer Lookback

Overview

At the end of summer, a relatively positive situation in Southern California contrasted with a more tumultuous national and international gas landscape. Despite experiencing the hottest summer recorded,[4] Southern California had mostly sufficient gas, although at higher prices, than in summer 2020 and entered fall with storage nearly full.

On the national and international front, a pair of hurricanes reduced gas production in the Gulf of Mexico, September storage supplies were low, liquified natural gas (LNG) prices set record highs,[5] and the combination of a heat wave and the El Paso outage caused gas prices to spike in California and the Southwest. By late October, a spate of mild weather and increased national storage injections had brought U.S. storage levels closer to the five-year average. However, international scarcity and the El Paso outage remain wild cards for the coming winter.

Hurricanes

Hurricane Ida, which made landfall on August 29, disrupted supply in the Gulf of Mexico and contributed to September price pressures. The hurricane initially caused 90 percent of offshore gas production facilities in the Gulf of Mexico to be shut in. A month after landfall, Gulf gas production remained 600 million cubic feet per day (MMcfd) below its pre-Ida level of nearly 3

[3] SoCalGas Tariff Rule 23: https://tariff.socalgas.com/regulatory/tariffs/tm2/pdf/23.pdf.

[4] National Oceanic and Atmospheric Administration (NOAA) reported 18.4 percent of the contiguous U.S. experienced hottest recorded temperatures on record, including California. See: https://www.noaa.gov/news/summer-2021-neck-and-neck-with-dust-bowl-summer-for-hottest-on-record.

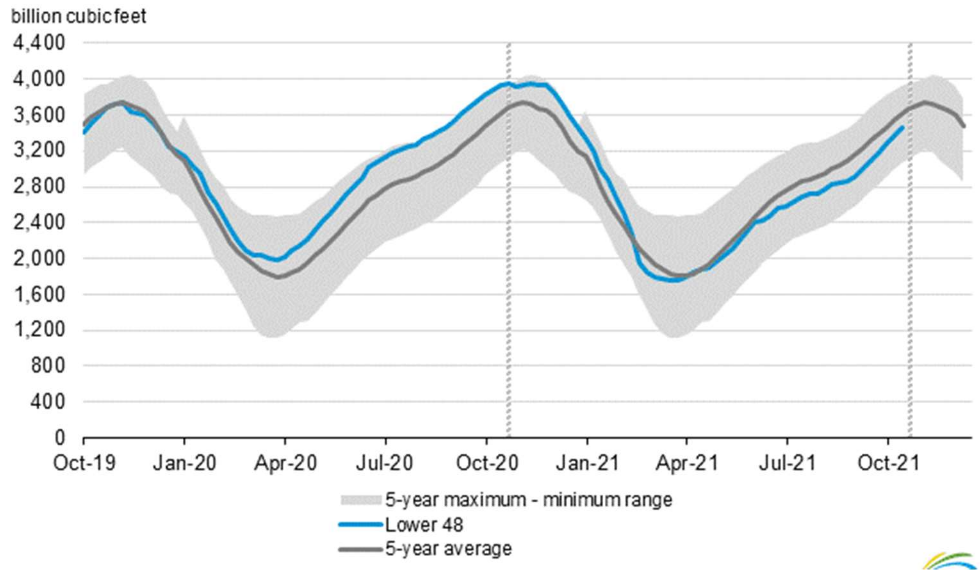
[5] EIA report "U.S. liquefied natural gas exports grew to record highs in the first half of 2021," July 27, 2021. See: https://www.eia.gov/todayinenergy/detail.php?id=48876.

billion cubic feet per day (Bcfd).[6] Hurricane Nicholas, which hit Texas on September 14, contributed to delays in bringing back production.

Storage

At the end of September, nationwide storage inventories were 6.9 percent lower than the five-year average, as shown in Figure 1. By October 15, the gap had closed considerably, with national storage within 4.2 percent of the five-year average.[7] The increase in national storage supply calmed gas markets,[8] but forward prices remain higher than in recent years. The U.S. Energy Information Administration (EIA) predicted that customers who heat their homes with gas will pay 30 percent more on average this winter.[9]

Figure 1. EIA Working Gas in Storage Compared with the Five-Year Maximum and Minimum



Source: EIA

LNG and the International Market

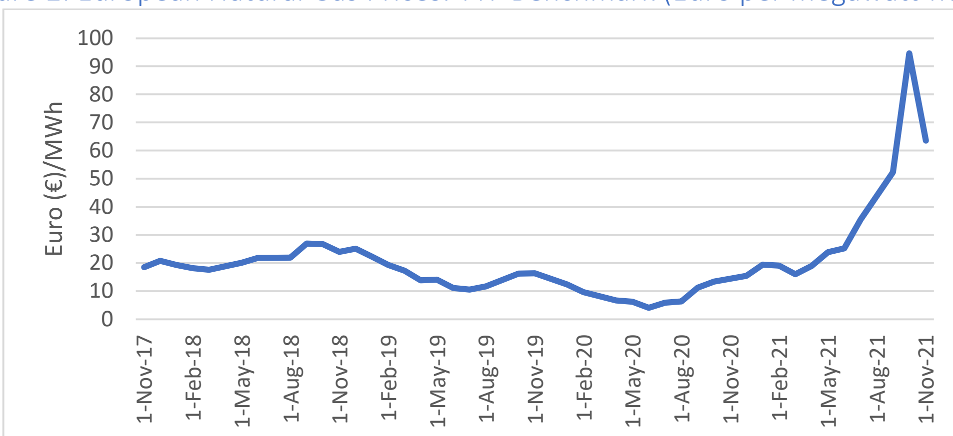
U.S. LNG exports reached record highs in the first half of 2021, averaging 9.6 Bcfd,[10] 40 percent higher than in 2020.[11]According to the EIA, by the end of 2021, average exports are expected to

[6] S&P Global Platt's Gas Daily, "NYMEX Henry Hub gas nears $6 on supply concerns, lingering Ida impact," September 29, 2021.
[7] EIA Weekly Natural Gas Storage Report, October 15: Weekly Natural Gas Storage Report - EIA.
[8] S&P Global Platt's Daily, "Latest weekly US gas storage build lifts deficit to 4% below five-year average: Winter supply concerns wane," October 22, 2021.
[9] EIA "Winter Fuels Outlook," October 2021: Short-Term Energy Outlook (eia.gov).
[10] EIA, "U.S. liquefied natural gas exports grew to record highs in the first half of 2021," July 27, 2021. See: https://www.eia.gov/todayinenergy/detail.php?id=48876.
[11] Department of Energy LNG Monthly Report for June 2021, published August 2021: https://www.energy.gov/sites/default/files/2021-09/LNG%20Monthly%20June%202021_1.pdf.

exceed 11 Bcfd or almost 50 percent more than the 2020 average.[12] Approximately 38 percent of U.S. LNG exports are sent to East Asia, and 30 percent are sent to Europe and Central Asia.[13] Thus, high prices in those regions may impact the U.S. gas market.

Weak summer injection in Europe has led to historic low storage inventories. Prices hit historic highs this fall (see Figure 2) and are expected to remain high through the winter. Chinese LNG demand is also expected to increase due to a coal shortage. Other international issues are creating a confluence of events that will increase demand for exports of U.S. LNG. According to Bloomberg News, the "stage is set for an all-out scramble among Asia, Europe, the Middle East, and South America for shipments of LNG from exporters such as the Qatar, Trinidad and Tobago, and the U.S."[14] However, finite U.S. LNG export facilities will limit the amount of gas that can be sent overseas.

Figure 2. European Natural Gas Prices: TTF Benchmark (Euro per megawatt-hour)



Source: Yahoo! Finance

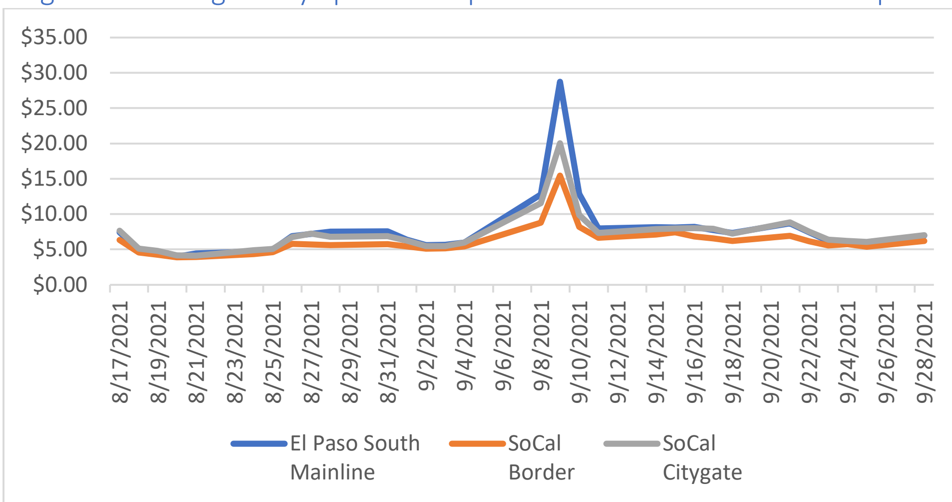
El Paso Outage

While the factors mentioned above impact national gas prices, the El Paso outage has a localized impact on Southern California. The August 15 pipeline explosion on the El Paso interstate pipeline serving SoCalGas' Southern Zone reduced the amount of gas flowing west from the Permian gas production basin by nearly 570 MMcfd.[15] While there is still sufficient physical pipeline capacity via alternative routes on the El Paso system to fully supply SoCalGas' Southern

[12] EIA, "U.S. liquefied natural gas exports grew to record highs in the first half of 2021," July 27, 2021. See: https://www.eia.gov/todayinenergy/detail.php?id=48876.
[13] DOE LNG Monthly Report for July 2021, published September 2021: https://www.energy.gov/sites/default/files/2021-09/LNG%20Monthly%20July%202021_0.pdf.
[14] Bloomberg News, "Europe's Energy Crisis Is Coming for the Rest of the World, Too," September 26, 2021: https://www.bloomberg.com/news/articles/2021-09-27/europe-s-energy-crisis-is-about-to-go-global-as-gas-prices-soar.
[15] S&P Global Platts Gas Daily, "Permian winter 2022 gas prices surge amid rising alarm over West Texas supply," October 6, 2021.

Zone, California gas customers must compete for the reduced gas supply with consumers in upstream states such as Arizona and New Mexico. When gas demand is moderate, there is enough to go around with little price impact. However, on high demand days, such as during the heat wave lasting from September 4 to 11, 2021, prices jumped. On September 9, average spot prices exceeded $20 per million British thermal units (MMBtu) at the SoCal Citygate and $28/MMBtu on El Paso's South Mainline in the Arizona-Nevada region, the interstate pipeline impacted by the outage, see Figure 3 below.

Figure 3. Average Daily Spot Prices per MMBtu After the El Paso Rupture



Source: Natural Gas Intelligence

The disruption caused by the El Paso outage prompted action to preserve gas system reliability. SoCalGas issued a Curtailment Watch for its Southern Zone from August 27 to September 14. While curtailments were avoided, the SoCalGas System Operator—and the SoCalGas Gas Acquisition Department, in its role as provider of last resort—purchased a combined 485,734 MMBtu (roughly 469 MMcfd) of gas under Rule 41 to support Southern Zone reliability during this period. They paid prices of up to $45/MMBtu for a total purchase price of over $12 million.[16] If found reasonable, these costs, less the amount the gas was sold for, will be passed on to customers in transportation rates.[17,18]

[16] During the same period in 2020, when there was also a heat wave and a more moderate price spike, the multi-day average spot price was $3.74. At that price, 485,734 MMBtu of gas would have cost roughly $1.8 million.
[17] SoCalGas Tariff Rule 41: https://tariff.socalgas.com/regulatory/tariffs/tm2/pdf/41.pdf.
[18] SoCalGas Data Request Response, October 1, 2021. This gas was delivered to both the Ehrenberg and the Otay Mesa receipt points.

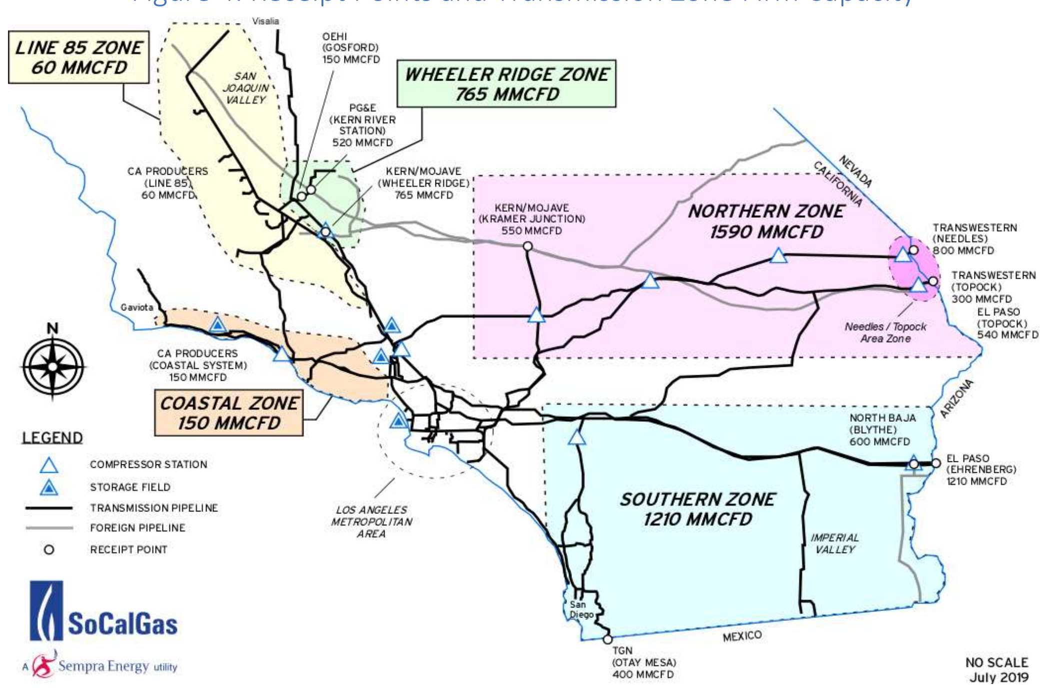
The El Paso rupture is under National Transportation Safety Board (NTSB) investigation, and there is currently no information on when the El Paso pipeline will return to service.[19] Some energy traders anticipate that it will be out for months.[20]

Supply Outlook

Transmission Pipelines

There are three major transmission zones within the SoCalGas system—the Northern Zone, Southern Zone, and Wheeler Ridge Zone. There are two other zones that 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 within a zone can impact the overall transmission capacity of the system.

Figure 4. Receipt Points and Transmission Zone Firm Capacity



Source: SoCalGas

In staff's analyses, both the Line 85 and Wheeler Ridge Zones are assumed to be able to receive the capacity shown on the map above: 60 and 765 MMcfd, respectively.

[19] National Transportation Safety Board ongoing investigation. See: https://www.ntsb.gov/investigations/Pages/PLD21FR003.aspx.

[20] Bloomberg, "New England, California to See Soaring Energy Costs This Winter," September 20, 2021. See: https://www.bloomberg.com/news/articles/2021-09-20/new-england-california-to-see-soaring-energy-costs-this-winter.

In the Northern Zone, Line 4000 returned to service on October 1, 2021, at increased pressure compared to recent years. However, both Line 235-2 and Line 4000 continue to operate below their nominal capacity, which reduces the overall capacity of the zone. Line 3000 is also expected to be out of service for required maintenance until December 31. This outage reduces system flexibility by reducing access to alternate interstate pipelines, but it does not reduce overall Northern Zone capacity. The analyses below assume Northern Zone capacity of 1,250 MMcfd compared to the 870 MMcfd it has been operating at in in recent months.

There are several nuances to Southern Zone capacity that cause staff to assume different capacities in different months. While it is technically possible to receive 1,210 MMcfd in the Southern Zone, that would require large deliveries to the Otay Mesa receipt point, which has historically been seldom used. Given the El Paso outage, such receipts would likely only occur via LNG deliveries from Costa Azul. Customers seeking LNG supplies would likely need to compete with high-priced international markets.[21]

The current physical capacity of the Ehrenberg receipt point is 980 MMcfd due to a longstanding pressure reduction related to the Pipeline Safety Enhancement Plan (PSEP) (202 MMcfd) and the loss of a right-of-way on SoCalGas Line 2000 (30 MMcfd). However, the El Paso outage has reduced the average amount of gas being delivered to Ehrenberg.

As described above, the El Paso outage puts California customers in competition for gas supply with customers upstream in Arizona and New Mexico. The operational intricacies of the El Paso pipeline system combined with upstream purchasing dynamics make it impossible to pin down exactly how much gas will be delivered to Ehrenberg this winter. Flows will vary because it will be easier for Southern Zone customers to get gas when demand and competition are low and harder when demand and competition are high, as shown in Figure 5 below.

As an example of this principle, deliveries to Ehrenberg averaged 535 MMcfd during the August 27 to September 14 Curtailment Watch, which coincided with high demand due to the September 4-11 heat wave. During the period from September 15 to 30, when weather was milder and demand lower, average deliveries were 552 MMcfd. Deliveries increased around the beginning of October, averaging 647 MMcfd from October 1 to 25 and reaching a peak of 715 MMcfd on October 13. However, during this period system demand rose above 2.4 Bcf on only one day.

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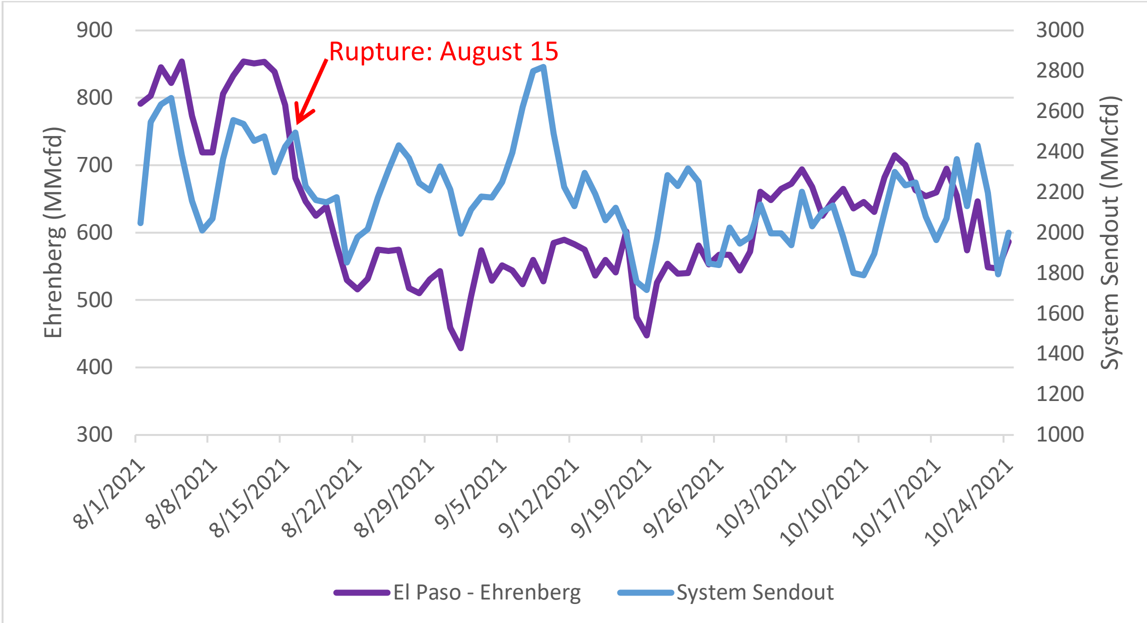
[21] The high prices for deliveries to Otay Mesa during the September price spike support the assumption that gas flowing to that receipt point is LNG and that its price is impacted by international markets.

Figure 5. Ehrenberg Receipts and Total System Demand After Pipeline Rupture



Source: SoCalGas Envoy

Given the uncertainty regarding future deliveries, staff uses a midpoint estimate of 600 MMcfd for Ehrenberg in most analyses as long as the El Paso pipeline outage continues. The hottest days of the heat wave, September 8-9, saw SoCalGas demand of about 2.8 billion cubic feet (Bcf) and Ehrenberg deliveries of 559 and 528 MMcfd, respectively. Since average winter demand is roughly 2.8 Bcf, staff see that period as potentially indicative of winter deliveries. At the same time, staff note the higher deliveries beginning October 1 and wish to factor in the possibility that more gas became available after that point. For the scenarios in which El Paso is in service, staff assume 980 MMcfd is delivered to Ehrenberg.

For October, staff assume there are no deliveries to Otay Mesa due to expected mild weather. Staff assume that Otay Mesa receives an average 30 MMcfd in November and 50 MMcfd December through March based on last year's assumptions and receipts. These average assumptions are used for the gas balance analysis. A slightly higher figure of 100 MMcfd, based on high demand day deliveries in recent years, is used for the 1-in-10 peak day analyses.

Given the uncertainty surrounding Southern Zone receipts if the El Paso outage continues, staff also includes one set of alternative analyses based on deliveries of 730 MMcfd to Ehrenberg, with no deliveries at Otay Mesa to provide a counterpoint to the other assumptions.

Gas Storage Facilities

Aliso Canyon's maximum allowable inventory is currently set at 34 Bcf.[22] However, a Proposed Decision and an Alternate Proposed Decision in the Aliso Canyon Investigation, (I.) 17-02-002, were issued on October 1 that propose increasing the Aliso Canyon maximum inventory to 68.6 and 41.2 Bcf, respectively. These proposed decisions are scheduled for a Commission vote on November 4.

Storage levels may increase in November if the CPUC approves either of the two recent proposals. If an increased inventory level is approved, the amount of injection will depend on the weather, customer behavior, and system conditions before mid-winter. Due to the uncertainty around potential increases in storage, this analysis makes no assumption that additional injections will occur and begins with the storage numbers as of September 30, 2021. Table 1 below compares the amount of gas in storage at the end of September in 2020 and 2021. The difference in total storage inventories shown can be attributed to different injection patterns during the two years.

Table 1: Total SoCalGas Storage Inventory

Bcf	Sept. 30, 2020	Sept. 30, 2021
Non-Aliso	45.5	47.7
Aliso Canyon	33.5	33.4
Total	79.0	81.1
Percent Full (Aliso + Non-Aliso)	94%	96%

Source: Envoy

Gas Balance Analysis

Gas demand figures for the winter are taken from the forecasts in the *2020 California Gas Report*.[23] Staff prepared gas balances in order to provide an assessment independent of SoCalGas' own assessment.[24] 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 occur. 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.

A gas balance does not simulate operations hydraulically to determine constraints or assess hourly operations. Since pipelines deliver roughly the same amount of gas every hour, large

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[22] D.20-11-004 Ordering Paragraph 1 maintained the interim Aliso Canyon storage capacity between zero to 34 Bcf.

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

[24] 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.

ramps in hourly demand can strain the gas system even when daily demand appears to be met by the total amount of pipeline and storage gas available over the entire 24-hour period. These fluctuations in intraday demand and withdrawals are not captured in the gas balances.

It is important to recognize that the forecasts used in the gas balances are for *average* daily demand for each month under two scenarios: average weather and 1-in-35-year cold weather/dry hydro.[25] There will be days that have higher or lower demand than the averages shown. In addition, 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.

The first gas balance scenario presented in the Appendix below, Scenario A-1, assumes that weather is average and supplies to the Ehrenberg receipt point are limited throughout the winter due to the El Paso pipeline outage. All other pipelines are assumed to be operating at the capacities described above, and storage begins at its actual September 30 level. Scenario A-1 meets average demand in all months but does not maintain the ideal 15 percent reserve margin for any of the winter months. A margin provides a buffer for unexpected outages or cold weather. Storage withdrawals are needed to meet customer demand on average weather days in December, January, and February.[26]

Scenario A-2 is the best-case scenario. It assumes weather is average and the El Paso pipeline returns December 1, 2021, which increases gas receipts at the Ehrenberg receipt point. All other assumptions are the same as in Scenario A-1. Scenario A-2 meets average demand in all months. It maintains a 30 percent reserve margin in March but does not maintain a 15 percent reserve margin during the other months. Storage withdrawals are needed to meet customer demand on average weather days in December.

Scenario B-1 is the worst-case scenario. It evaluates gas demand under a 1-in-35-year cold weather/dry hydro forecast. The pipeline supply and storage assumptions are the same as Scenario A-1, with the El Paso outage assumed to last all winter. Scenario B-1 meets cold winter average demand in all months but does not maintain a 15 percent reserve margin for any of the winter months. Storage withdrawals are needed to meet average customer demand from

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[25] A 1-in-35 cold weather/dry hydro *year* is different from a 1-in-35 extreme peak *day*. Under the 1-in-35 extreme peak day design standard set by the CPUC, all noncore can be curtailed. Since 1-in-35 cold weather/dry hydro year looks at average demand within the entire year, it is less stringent on a daily basis than the 1-in-35 peak day standard. See D.02-11-073 and D.06-09-039 for the establishment of reliability standards.

[26] Withdrawals from Aliso Canyon may occur if any of the four conditions of the Withdrawal Protocol are triggered: https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/news_room/newsupdates/2019/updatedwithdrawalprotocol-2019-07-23-v2.pdf.

November through February.[27] In this scenario, the storage fields are significantly depleted by the end of winter, which could result in low withdrawal capacity if a peak day were to occur late in the season.

Scenario B-2 uses the same assumptions as Scenario B-1 above except the El Paso pipeline returns to service on December 1, 2021. Scenario B-1 meets average demand in all months but does not maintain a 15 percent reserve margin for any of the winter months except March. Storage withdrawals are needed to meet average customer demand from November through February.[28] However, with the El Paso pipeline back in service, end-of-winter storage levels are significantly higher than in Scenario B-1.

The Alternative Scenario assumes average weather and a winter-long El Paso outage. It maintains most of the pipeline assumptions of the other scenarios but assumes that 730 MMcfd is delivered to Ehrenberg and no gas is delivered to Otay Mesa. In this scenario, average demand is met in all months, but a 15 percent reserve margin is not maintained in any month except November. Storage withdrawals are required in December, January, and February to meet customer demand. However, season-end storage levels are 7.2 Bcf higher than in Scenario A-1, which also assumes average weather and a winter-long El Paso outage but uses a lower estimate for Southern Zone deliveries.

1-in-10 Peak Day Analysis

In addition to the gas balances, which show the impact of average daily demand for normal and cold winter scenarios, staff performed best-, mid-, and worst-case 1-in-10 peak *day* analyses for each month of the winter. Staff also include an alternative scenario that assumes 730 MMcfd in deliveries at Ehrenberg, and no deliveries at Otay Mesa to provide a counterpoint to the other scenarios. The 1-in-10 scenarios build off the gas balances, using the month-end storage inventory level in the relevant gas balance scenario to determine the available withdrawal capacity.

The SoCalGas system is able to support 1-in-10 peak day demand all winter in the best-case scenario, in which the peak day occurs in the midst of an average weather winter and the El Paso pipeline returns to service on December 1 (Table 2). In the mid-case scenario—average weather and a winter-long El Paso outage (Table 3)—the SoCalGas system could not support 1-in-10 peak demand in December and January. In the worst-case scenario—a cold and dry winter and a winter-long El Paso pipeline outage (Table 4)—the SoCalGas system could not support peak day demand in any month except November.

[27] See footnote 24.
[28] See footnote 24.

The alternative scenario assumes average weather, a winter-long El Paso outage, deliveries of 730 MMcfd to Ehrenberg, and no deliveries to Otay Mesa. Using these assumptions, SoCalGas is not able to support a 1-in-10 peak day scenario in December and January.

The analyses below do not model hourly peaks, only lengthy hydraulic modeling studies can dynamically simulate hourly operations and capture pressure drops within the gas day.

The demand figures in Column (a) were provided by SoCalGas through a data request and represent a peak day in each month.[29] Column (b) shows the pipeline capacity assumed in each respective scenario, with 100 MMcfd assumed for Otay Mesa rather than the 50 MMcfd used in the gas balances.[30,31] In Column (c) a combined withdrawal capacity from all four fields is used based on the month-end inventory for each scenario from the gas balances and confidential 2021 withdrawal curves from SoCalGas.[32] No maintenance-related reductions are from assumed December through March.[33] The shortfalls displayed in column (e) represent the estimated volume of curtailments required if a peak day occurs.

[29] The California Gas Report includes one peak day demand figure, which typically corresponds with the coldest day in December and/or January. Since the coldest days in November, February, and March typically are not as cold as those in December and January, staff requested more accurate demand figures for those months from the utility.
[30] Otay Mesa historical receipts from recent winters show approximately 100 MMcfd delivered on some high demand days. The Gas Balance assumes that 50 MMcfd is delivered to Otay Mesa on an average day as described in the Gas Balance Analysis section. Thus, an additional 50 MMcfd is added to Column (b) for peak day demand.
[31] In the Alternative Scenario, no receipts are assumed at Otay Mesa.
[32] SoCalGas maintains that its withdrawal curves are confidential and protected from public disclosure because the data is market sensitive information. Staff are not able to directly verify these withdrawal curves. However, staff can track public data on daily available withdrawal capacity from SoCalGas's Envoy system and compare it to the withdrawal curves.
[33] SoCalGas performs Storage Integrity Management Plan (SIMP) maintenance at all its storage fields to meet state and federal regulations. In winter 2020-21, SoCalGas performed SIMP work throughout the winter to comply with California Geologic Energy Management Division (CalGEM) regulations. In an October 15, 2021, data request response, SoCalGas stated that SIMP work "…almost completely ramps down the Reassessments during December and January and focuses mostly on Abandonments during that time. SoCalGas will still be responsible for approximately 60 reassessments in 2022 based on the current 24-month CalGem requirement; in order to meet that goal, work will resume in February." SoCalGas subsequently stated in a conversation on October 25, 2021, that if there were reliability concerns in February, SIMP work would be postponed.

Table 2. 1-in-10 Peak Day Analysis Best-Case Scenario—Average Weather Winter; El Paso Returns in December (MMcfd)

	(a) 1-in-10 Peak Day Demand	(b) Total Pipeline Capacity	(c) Estimated Total System Withdrawal Capacity	(d) Total System Capacity (d=b+c)	(e) Surplus/ Shortfall (e=d-a)
November	4,209	2,775	2,003	4,778	569
December	4,967	3,155	2,373	5,528	561
January	4,891	3,155	2,373	5,528	637
February	4,480	3,155	2,373	5,528	1,048
March	4,133	3,155	2,373	5,528	1,395

Table 3. 1-in-10 Peak Day Analysis Mid-Case Scenario—Average Weather Winter with El Paso Outage (MMcfd)

	(a) 1-in-10 Peak Day Demand	(b) Total Pipeline Capacity	(c) Estimated Total System Withdrawal Capacity	(d) Total System Capacity (d=b+c)	(e) Surplus/ Shortfall (e=d-a)
November	4,209	2,775	2,003	4,778	569
December	4,967	2,775	2,105	4,880	(87)
January	4,891	2,775	1,943	4,718	(173)
February	4,480	2,775	1,812	4,587	107
March	4,133	2,775	2,008	4,783	650

Table 4. 1-in-10 Peak Day Analysis Worst-Case Scenario—Cold and Dry Weather Winter with El Paso Outage (MMcfd)

	(a) 1-in-10 Peak Day Demand	(b) Total Pipeline Capacity	(c) Estimated Total System Withdrawal Capacity	(d) Total System Capacity (d=b+c)	(e) Surplus/ Shortfall (e=d-a)
November	4,209	2,775	1,994	4,769	560
December	4,967	2,775	1,911	4,686	(281)
January	4,891	2,775	1,574	4,349	(542)
February	4,480	2,775	1,307	4,082	(398)
March	4,133	2,775	1,307	4,082	(51)

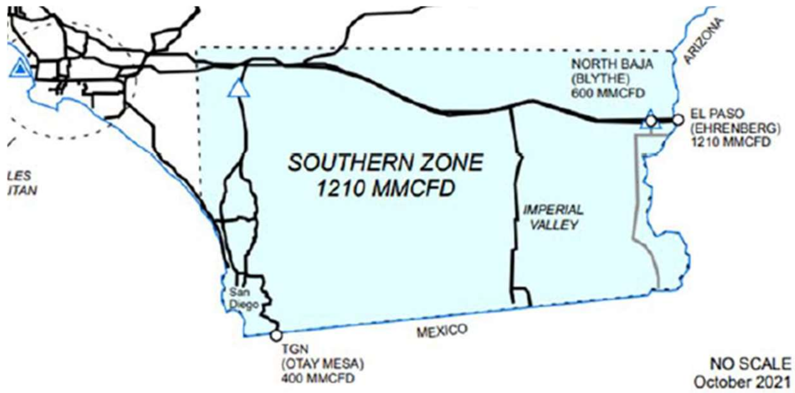
Table 5. 1-in-10 Peak Day Analysis Alternative Scenario—Average Weather Winter, El Paso Outage, Higher Southern Zone Deliveries (MMcfd)

	(a) 1-in-10 Peak Day Demand	(b) Total Pipeline Capacity	(c) Estimated Total System Withdrawal Capacity	(d) Total System Capacity (d=b+c)	(e) Surplus/ Shortfall (e=d-a)
November	4,209	2,805	2,033	4,838	629
December	4,967	2,805	2,123	4,928	(39)
January	4,891	2,805	2,054	4,859	(32)
February	4,480	2,805	1,972	4,777	297
March	4,133	2,805	2,168	4,973	840

Southern Zone Analysis

Staff estimate that, if the El Paso pipeline is not repaired, roughly 600 MMcfd of gas will be delivered to Ehrenberg and up to 100 MMcfd to Otay Mesa on a peak day, for a Southern Zone total of 700 MMcfd. The Southern Zone has no direct access to gas stored in the Northern Zone. However, storage withdrawals can support Southern Zone reliability indirectly in two ways. They can allow all gas delivered to the Southern Zone to stay there, with none being sent west toward the coast, and some amount of gas can be moved north to south on the pipelines if that supply is backfilled from storage. Staff cannot currently estimate how much gas can supplement what is delivered to Ehrenberg and Otay Mesa.

Figure 6. Southern Zone Map Detail



Source: SoCalGas

As shown in Table 6, SoCalGas forecasts total peak day Southern Zone demand of 1,159 MMcfd, with core—or residential and small commercial customers—making up 910 MMcfd of the total. If only 700 MMcfd is available, there could be a 459 MMcfd gap between Southern Zone supply and total demand on a peak day and a 210 MMcfd gap between supply and core demand. If curtailments are necessary, noncore—gas-fired electric generation[34] and industrial customers—would be curtailed first. However, given the limited noncore demand in the Southern Zone, there is a chance that cuts could reach core customers.

Table 6. Southern Zone Winter 1-in-10 Peak Day Demand (MMcfd)

Year	SoCalGas Core	SDG&E Core	Subtotal Core Demand	Noncore Non-EG	Noncore EG	Subtotal Noncore Demand	Total Demand
2021	511	399	910	59	190	249	1,159

Source: SoCalGas Data Request Response 10/8/2021

Given the size of the peak day gap and uncertainty about how much gas can move north to south, staff has some concern regarding the potential for Southern Zone curtailments on days that are merely cold if the El Paso pipeline is not repaired. To estimate the likelihood of such cuts, staff looked at historical deliveries to the Southern Zone. To account for the possibility that the supply assumptions are too conservative, staff counted the number of days that Southern Zone deliveries exceeded 700, 800, and 900 MMcfd. As shown in Table 7, Southern Zone deliveries exceeded 900 MMcfd on between 11 and 33 percent of winter days in the last three years.

As noted above, under normal conditions, some gas may flow west toward the coast rather than south toward San Diego, so these delivery numbers may somewhat overstate Southern Zone

[34] Under Rule 23, gas-fired electric generation is curtailed first, in part because it is possible to substitute electric supplies from other regions for local electric generation.

demand. Nonetheless, they do indicate the potential for tight supplies in the Southern Zone this winter that could lead to volatile gas prices and possibly to gas reliability concerns.

Table 7. Number of Winter Days Southern Zone Deliveries Exceeded 700, 800, and 900 MMcfd

Winter	Days Above 700 MMcfd	Percent of Winter Days Above 700 MMcfd	Days Above 800 MMcfd	Percent of Winter Days Above 800 MMcfd	Days Above 900 MMcfd	Percent of Winter Days Above 900 MMcfd
2018-2019	101	83%	66	55%	13	11%
2019-2020	116	95%	104	85%	40	33%
2020-2021	113	93%	81	67%	33	27%

Source: Envoy

Appendix

SoCalGas Monthly Gas Balance

Scenario A-1

Normal weather. El Paso outage persists all winter. Line 4000 returns at increased pressure by October 1.

SoCalGas Monthly Gas Balance NORMAL WEATHER		Oct	Nov	Dec	Jan	Feb	Mar
California Gas Report 2021 Demand (MMcfd)							
Core		693	1,018	1,441	1,374	1,354	1,092
Noncore including EG		1,209	1,158	1,204	1,092	1,106	949
Wholesale & International		348	388	473	452	436	326
Co. Use and LUAF		29	33	40	37	37	30
Subtotal Demand		2,279	2,597	3,158	2,955	2,933	2,397
Storage Injection (Non-Aliso Fields)		87	0	0	0	0	178
Storage Injection (Aliso)		19	0	0	0	0	100
Storage Injection Total		*106*	*0*	*0*	*0*	*0*	*278*
System Total Throughput		2,385	2,597	3,158	2,955	2,933	2,675
Supply (MMcfd)							
California Line 85 Zone		60	60	60	60	60	60
Wheeler Ridge Zone		765	765	765	765	765	765
Blythe (Ehrenberg) into Southern Zone		600	600	600	600	600	600
Otay Mesa into Southern Zone		0	30	50	50	50	50
Kramer Junction into Northern Zone		550	550	550	550	550	550
North Needles into Northern Zone		700	700	700	420	420	420
Topock into Northern Zone		0	0	0	280	280	280
Sub Total Pipeline Receipts		2,675	2,705	2,725	2,725	2,725	2,725
Storage Withdrawal (Non-Aliso Fields)		0	0	253	150	100	0
Storage Withdrawal (Aliso)		0	0	180	80	108	0
Total Supply		2,675	2,705	3,158	2,955	2,933	2,725
DELIVERABILITY BALANCE (MMcfd)		290	108	0	0	0	50
Reserve Margin		12%	4%	0%	0%	0%	2%
Non-Aliso Month-End Storage Inventory (Bcf)	47.7	50.40	50.4	42.6	37.9	35.1	40.6
Aliso Month-End Storage Inventory (Bcf)	33.4	34.00	34.0	28.4	25.9	22.9	26.0
Total Storage Inventory	81.1	84.4	84.4	71.0	63.8	58.0	66.6

SoCalGas Monthly Gas Balance

Scenario A-2

Normal weather. El Paso returns December 1. Line 4000 returns at increased pressure by October 1.

SoCalGas Monthly Gas Balance NORMAL WEATHER		Oct	Nov	Dec	Jan	Feb	Mar
California Gas Report 2021 Demand (MMcfd)							
Core		693	1,018	1,441	1,374	1,354	1,092
Noncore including EG		1,209	1,158	1,204	1,092	1,106	949
Wholesale & International		348	388	473	452	436	326
Co. Use and LUAF		29	33	40	37	37	30
Subtotal Demand		2,279	2,597	3,158	2,955	2,933	2,397
Storage Injection (Non-Aliso Fields)		87	0	0	0	0	0
Storage Injection (Aliso)		19	0	0	0	0	0
Storage Injection Total		*106*	*0*	*0*	*0*	*0*	*0*
System Total Throughput		2,385	2,597	3,158	2,955	2,933	2,397
Supply (MMcfd)							
California Line 85 Zone		60	60	60	60	60	60
Wheeler Ridge Zone		765	765	765	765	765	765
Blythe (Ehrenberg) into Southern Zone		600	600	980	980	980	980
Otay Mesa into Southern Zone		0	30	50	50	50	50
Kramer Junction into Northern Zone		550	550	550	550	550	550
North Needles into Northern Zone		700	700	700	420	420	420
Topock into Northern Zone		0	0	0	280	280	280
Sub Total Pipeline Receipts		2,675	2,705	3,105	3,105	3,105	3,105
Storage Withdrawal (Non-Aliso Fields)		0	0	28	0	0	0
Storage Withdrawal (Aliso)		0	0	25	0	0	0
Total Supply		2,675	2,705	3,158	3,105	3,105	3,105
DELIVERABILITY BALANCE (MMcfd)		290	108	0	150	172	708
Reserve Margin		12%	4%	0%	5%	6%	30%
Non-Aliso Month-End Storage Inventory (Bcf)	47.7	50.4	50.4	49.5	49.5	49.5	49.5
Aliso Month-End Storage Inventory (Bcf)	33.4	34.0	34.0	33.2	33.2	33.2	33.2
Total Storage Inventory	81.1	84.4	84.4	82.8	82.8	82.8	82.8

SoCalGas Monthly Gas Balance

Scenario B-1

Cold weather and dry hydro year. El Paso outage persists all winter. Line 4000 returns at increased pressure by October 1.

SoCalGas Monthly Gas Balance COLD WEATHER		Oct	Nov	Dec	Jan	Feb	Mar
California Gas Report 2021 Demand (MMcfd)							
Core		713	1,098	1,607	1,526	1,502	1,188
Noncore including EG		1,232	1,208	1,248	1,139	1,130	970
Wholesale & International		358	410	514	494	470	353
Co. Use and LUAF		29	35	43	40	40	32
Subtotal Demand		2,332	2,751	3,412	3,199	3,142	2,543
Storage Injection (Non-Aliso Fields)		87	0	0	0	0	0
Storage Injection (Aliso)		19	0	0	0	0	0
Storage Injection Total		*106*	*0*	*0*	*0*	*0*	*0*
System Total Throughput		2,438	2,751	3,412	3,199	3,142	2,543
Supply (MMcfd)							
California Line 85 Zone		60	60	60	60	60	60
Wheeler Ridge Zone		765	765	765	765	765	765
Blythe (Ehrenberg) into Southern Zone		600	600	600	600	600	600
Otay Mesa into Southern Zone		0	30	50	50	50	50
Kramer Junction into Northern Zone		550	550	550	550	550	550
North Needles into Northern Zone		700	700	700	420	420	420
Topock into Northern Zone		0	0	0	280	280	280
Sub Total Pipeline Receipts		2,675	2,705	2,725	2,725	2,725	2,725
Storage Withdrawal (Non-Aliso Fields)		0	30	407	274	237	0
Storage Withdrawal (Aliso)		0	16	280	200	180	0
Total Supply		2,675	2,751	3,412	3,199	3,142	2,725
DELIVERABILITY BALANCE (MMcfd)		237	0	0	0	0	182
Reserve Margin		10%	0%	0%	0%	0%	7%
Non-Aliso Month-End Storage Inventory (Bcf)	47.7	50.4	49.5	36.9	28.4	21.8	21.8
Aliso Month-End Storage Inventory (Bcf)	33.4	34.0	33.5	24.8	18.6	13.6	13.6
Total Storage Inventory	81.1	84.4	83.0	61.7	47.0	35.4	35.4

SoCalGas Monthly Gas Balance

Scenario B-2

Cold weather and dry hydro year. El Paso returns December 1. Line 4000 returns at increased pressure by October 1.

SoCalGas Monthly Gas Balance COLD WEATHER		Oct	Nov	Dec	Jan	Feb	Mar
California Gas Report 2021 Demand (MMcfd)							
Core		713	1,098	1,607	1,526	1,502	1,188
Noncore including EG		1,232	1,208	1,248	1,139	1,130	970
Wholesale & International		358	410	514	494	470	353
Co. Use and LUAF		29	35	43	40	40	32
Subtotal Demand		2,332	2,751	3,412	3,199	3,142	2,543
Storage Injection (Non-Aliso Fields)		87	0	0	0	0	0
Storage Injection (Aliso)		19	0	0	0	0	0
Storage Injection Total		*106*	*0*	*0*	*0*	*0*	*0*
System Total Throughput		2,438	2,751	3,412	3,199	3,142	2,543
Supply (MMcfd)							
California Line 85 Zone		60	60	60	60	60	60
Wheeler Ridge Zone		765	765	765	765	765	765
Blythe (Ehrenberg) into Southern Zone		600	600	980	980	980	980
Otay Mesa into Southern Zone		0	30	50	50	50	50
Kramer Junction into Northern Zone		550	550	550	550	550	550
North Needles into Northern Zone		700	700	700	420	420	420
Topock into Northern Zone		0	0	0	280	280	280
Sub Total Pipeline Receipts		2,675	2,705	3,105	3,105	3,105	3,105
Storage Withdrawal (Non-Aliso Fields)		0	30	202	79	22	0
Storage Withdrawal (Aliso)		0	16	105	15	15	0
Total Supply		2,675	2,751	3,412	3,199	3,142	3,105
DELIVERABILITY BALANCE (MMcfd)		237	0	0	0	0	562
Reserve Margin		10%	0%	0%	0%	0%	22%
Non-Aliso Month-End Storage Inventory (Bcf)	47.7	50.4	49.5	43.2	40.8	40.2	40.2
Aliso Month-End Storage Inventory (Bcf)	33.4	34.0	33.5	30.3	29.8	29.4	29.4
Total Storage Inventory	81.1	84.4	83.0	73.5	70.6	69.6	69.6

SoCalGas Monthly Gas Balance

Alternative Scenario

Normal weather. El Paso outage persists all winter. Line 4000 returns at increased pressure by October 1. Ehrenberg receipts at 730 MMcf and no Otay Mesa supply.

SoCalGas Monthly Gas Balance NORMAL WEATHER		Oct	Nov	Dec	Jan	Feb	Mar
California Gas Report 2021 Demand (MMcfd)							
Core		693	1,018	1,441	1,374	1,354	1,092
Noncore including EG		1,209	1,158	1,204	1,092	1,106	949
Wholesale & International		348	388	473	452	436	326
Co. Use and LUAF		29	33	40	37	37	30
Subtotal Demand		2,279	2,597	3,158	2,955	2,933	2,397
Storage Injection (Non-Aliso Fields)		87	0	0	0	0	178
Storage Injection (Aliso)		19	0	0	0	0	100
Storage Injection Total		*106*	*0*	*0*	*0*	*0*	*278*
System Total Throughput		2,385	2,597	3,158	2,955	2,933	2,675
Supply (MMcfd)							
California Line 85 Zone		60	60	60	60	60	60
Wheeler Ridge Zone		765	765	765	765	765	765
Blythe (Ehrenberg) into Southern Zone		730	730	730	730	730	730
Otay Mesa into Southern Zone		0	0	0	0	0	0
Kramer Junction into Northern Zone		550	550	550	550	550	550
North Needles into Northern Zone		700	700	700	420	420	420
Topock into Northern Zone		0	0	0	280	280	280
Sub Total Pipeline Receipts		2,805	2,805	2,805	2,805	2,805	2,805
Storage Withdrawal (Non-Aliso Fields)		0	0	253	80	80	0
Storage Withdrawal (Aliso)		0	0	100	70	48	0
Total Supply		2,805	2,805	3,158	2,955	2,933	2,805
DELIVERABILITY BALANCE (MMcfd)		420	208	0	0	0	130
Reserve Margin		18%	8%	0%	0%	0%	5%
Non-Aliso Month-End Storage Inventory (Bcf)	47.7	50.40	50.4	42.6	40.1	37.8	43.4
Aliso Month-End Storage Inventory (Bcf)	33.4	34.00	34.0	30.9	28.7	27.4	30.5
Total Storage Inventory	81.1	84.4	84.4	73.5	68.8	65.2	73.8