# Aliso Canyon I.17-02-002 Phase 2: Modeling Report

BY STAFF OF THE CALIFORNIA PUBLIC UTILITIES COMMISSION
January 26, 2021

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# Executive Summary

The California Public Utilities Commission (CPUC) initiated the Aliso Canyon Well Failure Order Instituting Investigation (I.17-02-002, OII) to "determine the feasibility of minimizing or eliminating the use of Aliso Canyon Natural Gas Storage Facility while maintaining energy and electric reliability"[1] as required by Senate Bill 380.

In Phase 1 of the investigation, staff from the CPUC's Energy Division (ED staff) gathered input from stakeholders to create a Scenarios Framework that outlined the scenarios that would be modeled and the assumptions that would be used to determine whether Aliso Canyon usage could be minimized or eliminated given current rules and infrastructure. That Scenarios Framework—which laid out a plan for economic, hydraulic, and production cost modeling of the Southern California Gas Company (SoCalGas) system—was adopted in an Assigned Commissioner and Administrative Law Judge's Ruling at the end of Phase 1.[2]

The purpose of Phase 2 of the proceeding was to perform the modeling outlined in the Scenarios Framework and issue reports based on that analysis. Staff conducted most of the Phase 2 modeling. However, due to resource constraints, some hydraulic modeling scenarios were run by SoCalGas with oversight from ED staff and Los Alamos National Laboratories. The first report, which detailed ED staff results from the economic modeling, was released on November 2, 2020.[3] This second report includes the remaining results, which are the production cost modeling for minimum local generation scenarios, the hydraulic modeling for 1-in-10-year and 1-in-35-year design scenarios, and the feasibility assessment. These results have been presented and discussed at four public workshops, in June 2019, November 2019, July 2020 and October 2020.

Phase 3 of the proceeding is also underway concurrently with Phase 2. In Phase 3, the CPUC hired FTI Consulting to propose changes to the gas and electric system rules and infrastructure that would allow Aliso Canyon to be closed while still preserving reliability and just and reasonable rates. The consultant's report, which will include an analysis of the cost and feasibility of each proposal, is due in mid-2021. The CPUC is expected to issue a Phase 3 decision by the end of that year.

Stakeholders including environmental groups, the neighborhood adjacent to Aliso Canyon, and the Governor of the State of California have called for the closure of Aliso Canyon as a result of the massive leak in 2015.[4] While some parties assert that use of Aliso Canyon poses ongoing safety

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[1] I.17-02-002, Ordering Paragraph 1: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M173/K122/173122830.PDF

[2] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M254/K771/254771612.PDF

[3] https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=349931623

[4] Letter from Governor Newsom to CPUC https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/Nov%2018%202019%20Letter%20to%20President%20Batjer.pdf. Stakeholders calling for closure include Sierra Club and Food & Water Action.

issues, the California Geologic Energy Management Division (CalGEM)[5] has determined that the field is safe to operate up to an inventory of 68.6 billion cubic feet (Bcf). SoCalGas and other parties including the Southern California Publicly Owned Utilities (SCPOU), the Indicated Shippers, and The Utility Reform Network (TURN), contend that an inventory of 68.6 Bcf at Aliso Canyon is needed for reliability and price stability.

As directed by the Ordering Paragraph 1 of I.17-02-002, Energy Division's independent analysis through reliability and feasibility assessments indicates that the facility is needed to meet at least 520 million cubic feet per day (MMcfd) of withdrawals during a 1-in-10 peak demand day of winter 2030 assuming no policy-initiated changes in natural gas demand beyond those already incorporated into planning forecasts. Likewise, the CPUC's Results of Econometric Modeling issued November 2, 2020, concluded that Aliso Canyon helps prevent electric price volatility during summer, when natural gas is used for electric generation to support higher electric demand.

1. The key findings in this report are: Production Cost Modeling of the electric system showed that there would be significant reliability concerns if electric generation is curtailed to the Minimum Local Generation level. Curtailment to the Minimum Local Generation level, however, would decrease gas demand enough to allow reliable gas service without using Aliso Canyon.
2. 1-in-10 winter simulations demonstrated that Aliso Canyon is necessary to provide gas reliability in the 1-in-10-year winter reliability condition.
3. Summer simulations showed that summer demand can be met without Aliso Canyon.
4. Sensitivities on the 1-in-10 winter 2030 simulation quantified the Aliso Canyon inventory levels needed when non-Aliso Canyon storage fields are 37 percent, 50 percent, and 70 percent full.
5. 1-in-35 winter simulations showed that Aliso Canyon is not needed to meet core and minimum local electric generation demand when all other noncore demand is curtailed, largely due to lower gas demand when electric demand is curtailed down to Minimum Local Generation level.
6. The Feasibility Study showed the Aliso Canyon inventory levels needed for sustained cold periods. Aliso Canyon inventory of between 41.2 and 68.6 Bcf would be needed to ensure reliability depending on the pipeline capacity assumptions used.

## Background

SoCalGas's Aliso Canyon natural gas storage facility, located in the Santa Susana Mountains of Los Angeles County, is the largest natural gas storage facility in California. A major gas leak was discovered at Aliso Canyon 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.[6] The

[5] CalGEM was previously known as the Division of Oil, Gas, and Geothermal Resources or DOGGR.
[6] https://www.gov.ca.gov/2016/01/06/news19263/

CPUC subsequently required SoCalGas to leave 15 billion cubic feet (Bcf) of working gas in the facility that could be withdrawn to maintain reliability. On May 10, 2016, Senate Bill (SB) 380[7] was approved. Among other things, the bill:

1. Prohibited injection into Aliso Canyon until a safety review was completed and certified by the CalGEM[8] with concurrence from the CPUC;
2. Required CalGEM to set the maximum and minimum reservoir pressure;
3. Charged the CPUC with determining the range of working gas necessary to ensure safety and reliability and just and reasonable rates in the short term; and
4. Required the CPUC to open a proceeding to determine the feasibility of minimizing or eliminating use of Aliso over the long term while still maintaining energy and electric reliability for the region.

On February 9, 2017, pursuant to Senate Bill 380, the CPUC opened the extant proceeding, I.17-02-002, to determine the long-term feasibility of minimizing or eliminating the use of the facility while still maintaining energy and electric reliability for the Los Angeles region at just and reasonable rates.

# I. Production Cost Modeling

## Overview

Pursuant to Senate Bill (SB) 380 and the adopted Scenarios Framework, California Public Utilities Commission's Energy Division staff (staff) set forth the roadmap for three modeling streams to be completed in Phase 2 of the investigation—hydraulic modeling, production cost modeling, and economic modeling. This production cost modeling analysis serves two purposes. First, it answers the question of whether the elimination or minimization of Aliso Canyon causes any significant reliability effects, such as a change in Loss of Load Expectation (LOLE), Loss of Load Hours (LOLH), Expected Unserved Energy (EUE), or a significant change in electric production costs. Second, results are used to produce hourly gas demand profiles for subsequent use in a hydraulic model. This report summarizes the data collected, the study methods, and the resultant findings.

The study compares two scenarios. The Unconstrained scenario is meant to represent a system without constraints on the availability of natural gas, using a 1-in-10 gas design standard which provides a baseline that does not call for curtailment of noncore electric generators. For this scenario, staff used the Reference System Plan from the 2019-2020 Integrated Resources Plan (IRP) cycle[9] as a baseline of electric generation that will be online in the future—in 2022, 2026, and 2030, the IRP study years—as well as the Reference System Plan's proposed additions and retirements. The Unconstrained Scenario produced a plan detailing which electric generators would be operating and what their likely production patterns would be under the recently adopted Reference System

[7] Statues of 2016, chapter 14.
[8] DOGGR has since been renamed. It is now the California Geologic Energy Management Division or CalGEM.
[9] The 2019 Reference System Plan was adopted by the Commission in April 2020. Links to the decision and other materials are on this page of the CPUC website under "Reference System Plan Decision and Materials": https://www.cpuc.ca.gov/General.aspx?id=6442459770

Plan. The Unconstrained Scenario results covering the reliability and cost of dispatching electric generators also serve as a baseline to compare with the results of the Minimum Local Generation (MinLocGen) Scenario.

In contrast, the MinLocGen scenario curtails electric generation down to the minimum amount needed to meet Minimum Reliability Standards as required by the North American Electric Reliability Corporation (NERC). In keeping with the scenario framework, the MinLocGen case was run for study years of 2020, 2025, and 2030. The results of this scenario represent reliability and costs if a minimum amount of generation is maintained and all other gas-fired generation is curtailed.

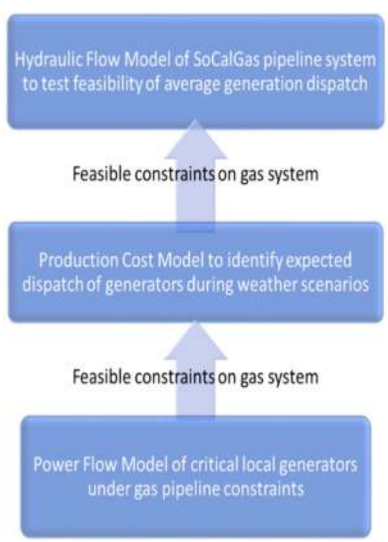
The study resulted in several main conclusions about use of Aliso Canyon and the negative impact of the MinLocGen level of electric generation curtailments including:

1. The MinLocGen scenario produced significant degradation to electric reliability in the summer in all study years relative to the Unconstrained scenario as measured by increased LOLE, although curtailment to the Minimum Local Generation level would decrease gas demand enough to allow reliable gas service without using Aliso Canyon.
2. The MinLocGen scenario increased electric production costs 3.3 percent, or about $121 million, relative to the Unconstrained scenario even though not all electric demand is met, due to increased dispatch of more expensive generation and imported electricity.
3. Emissions slightly decreased in the MinLocGen scenario in comparison to the Unconstrained scenario. This is unsurprising since in this scenario less electric demand was served.

## Introduction

As outlined in the Scenarios Framework, staff evaluated the impacts of closing Aliso Canyon through a "bottom-up" approach, as illustrated in Figure I – 1.

Figure I - 1 Bottom-Up Sequence of Studies



The Aliso Canyon gas storage field, along with three other gas storage fields, provides gas to 17 gas-fired electric generators in the greater Los Angeles region. These gas-fired electric generators provide a variety of grid services, such as: peaking (serving load during times of very high demand), ramping (the ability to rapidly increase power output to meet quick increases in demand), and base load (providing constant, dependable power output).

If gas supply to the 17 electric generators is reduced, it will affect their ramping ability, their ability to start up on short notice, and other operating parameters. In turn, electric system costs and reliability may also be impacted. These costs and reliability impacts can be estimated and quantified using a production cost model (PCM). The CPUC adopted the PCM approach in the Scenarios Framework and determined that Energy Division staff would perform PCM analysis to forecast hourly gas use for electric generation under the Unconstrained and MinLocGen Scenario.

A PCM is a software tool used to simulate electric grid operations then produce a distribution of cost and reliability outcomes and their associated probabilities. Staff used the Strategic Energy and Risk Valuation Model (SERVM) developed by Astrapé Consulting. SERVM simulates least-cost dispatch for a user-defined set of generating resources and loads. It calculates numerous electric reliability and cost metrics for a given study year, considering expected weather, overall economic growth, and performance of the generating resources. Data used in the model as well as more detail regarding the sources and calculations of the modeling inputs produced for the Integrated Resource Plan (IRP) Rulemaking (R.) 20-05-003 can be found on the CPUC website.

In the context of I.17-02-002, the PCM analysis serves two purposes. First, it answers the question of whether the elimination or minimization of Aliso Canyon causes any significant electric reliability effects, such as a change in Loss of Load Expectation, Loss of Load Hours, Expected Unserved Energy, or a change in electric production costs by 5 percent or more. Second, it produces gas demand profiles at an hourly level for the 1-in-10 peak day and 1-in-35 extreme peak day hydraulic modeling scenarios for gas reliability.

## PCM Approach and Method

Staff used the Reference System Plan from the 2019-2020 IRP cycle for a baseline of electric generation that will be online in the future (years 2020, 2025, and 2030), as well as the Reference System Plan's proposed additions and retirements.[10] Dispatching the Reference System Plan in the PCM model in the Unconstrained scenario is meant to reflect the 1-in-10 gas design standard, which does not call for curtailment of noncore electric generators. The Unconstrained scenario results demonstrate the electric reliability impacts and cost of dispatching electric generators to serve as a baseline, which are then compared with the results of the MinLocGen scenario.

The MinLocGen scenario is meant to reflect the implementation of SoCalGas' Rule No. 23 requirement to curtail noncore gas-fired electric generation as part of the 1-in-35 extreme peak day

[10] The Reference System Plan was adopted in D.20-03-028 and can be found here: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M331/K772/331772681.PDF.

reliability standard, which does call for curtailment of non-core electric generators. To determine which electric generation curtailment to simulate, staff used power flow modeling results gathered from the California Independent System Operator (CAISO) and Los Angeles Department of Water and Power (LADWP) to constrain electric generators needed to fulfill NERC Minimum Reliability Standards. Staff did not remove any generation from the Imperial Irrigation District (IID) area due to lack of a power flow study to develop minimum local generation requirements. However, staff do not consider IID generation to have a very significant impact on reliability in the CAISO area.

## Unconstrained and Minimum Local Generation Scenarios

Both the Unconstrained and the MinLocGen scenarios produced likely production patterns under different generation forecasts. By modeling the curtailment of electric generation, staff was able to simulate a significant gas supply curtailment in the SoCalGas system. Staff expected that removing Aliso Canyon entirely would likely result in significant gas curtailments, so to test the impacts of potential extreme effects, staff removed electric generators that were not needed for minimum local reliability in Southern California, including the planning areas of Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), and LADWP. Staff modeled the curtailment of gas-fired electric generation that was supplied by the SoCalGas system as an extreme simulation of the effects of removal of the Aliso Canyon storage field.

Due to modeling delays, modeling of the Unconstrained scenarios coincided with the CPUC's adoption of the 2020 Reference System Plan, which contained new electric demand and generation forecasts for certain study years. As a result, the Unconstrained scenarios were modeled for the years 2022, 2026, and 2030, while the MinLocGen scenarios as specified in the scenarios framework and modeled in the CAISO and LADWP power flow studies remained 2020, 2025, and 2030.

Staff found that the difference in study years did not make LOLE reliability results inconsistent, although discontinuities in electric generation (such as retirement of OTC plants and Diablo Canyon) complicate comparisons of production cost and imports, exports and other electric generation. For that reason, comparisons of generation and production costs focus on 2030 only.

Table 1-1 provides the September gas-fired electric generation megawatts (MW) modeled in the SoCalGas system for the Unconstrained and MinLocGen scenarios, as well as the percentage of generation that was removed from each unit type to arrive at the MinLocGen Scenario. September is used to model peak summer conditions on the electric grid. Combined cycle plants used in the model increase in 2025 relative to September 2020, as a combination of some new in basin (new Huntington Beach replacement) and out of basin (new Intermountain replacement) electric generation reaches commercial operation. By 2030, investment in transmission enables a reduction in local generation, and the MinLocGen requirements decrease relative to 2025. The percentage of generation removed increases in 2030, indicating more gas-fired plants are not needed for local reliability and thus are likely to be curtailed in extreme events. Note that for all three study years cogeneration remains at 592 MW in the MinLocGen scenario due to the same subset of cogeneration being curtailed.

Table I- 1 Thermal Generation Modeled in SCE, SDGE, IID and LADWP (MW) in September Months

| Unit Type | 2022 Unconstrained | 2020 MinLocGen | % Generation Removed |
|---|---|---|---|
| **Combined Cycle** | 9,580 | 7,255 | 24% |
| **Peaker** | 6,179 | 5,072 | 18% |
| **Cogen** | 1,126 | 592 | 47% |
| **Total** | 16,885 | 12,919 | 23% |
| **Unit Type** | **2026 Unconstrained** | **2025 MinLocGen** | **% Generation Removed** |
| **Combined Cycle** | 10,274 | 9,120 | 11% |
| **Peaker** | 6,281 | 4,802 | 24% |
| **Cogen** | 1,126 | 592 | 47% |
| **Total** | 17,681 | 14,514 | 18% |
| **Unit Type** | **2030 Unconstrained** | **2030 MinLocGen** | **% Generation Removed** |
| **Combined Cycle** | 10,043 | 6,991 | 30% |
| **Peaker** | 6,245 | 3,749 | 40% |
| **Cogen** | 1,126 | 592 | 47% |
| **Total** | 17,414 | 11,332 | 35% |

## PCM Inputs

The PCM modeling performed for the Aliso proceeding is based on work performed for the IRP, including the Reference System Plan adopted in CPUC decision D.20-03-028. Inputs are linked to the CPUC website and are explained in more detail below.[11]

1. Reference System Plan

   The Reference System Plan is the output of modeling that seeks to answer the question of what generating resources are likely to be operating in future years to 2030 and beyond. The Reference System Plan includes both the electric demand forecasted as well as the generating resources forecasted to meet that electric demand. It is the work of capacity expansion modeling done with the RESOLVE model that selects an optimal set of candidate resources to augment the baseline set of generators that already operate today. The new candidate resources represent the optimal set of capacity investments to meet the CPUC's goals to preserve reliability and minimize GHG emissions cost effectively.

[11] Modeling data used for PCM modeling is linked to the CPUC website here: https://www.cpuc.ca.gov/General.aspx?id=6442461894

RESOLVE was created by Energy+Environmental Economics (E3) and was adapted for use in the CPUC's IRP proceeding under the administration of Energy Division. RESOLVE is an optimal investment and operational model designed to inform long-term planning questions around renewables integration in systems with high penetration levels of renewable energy.

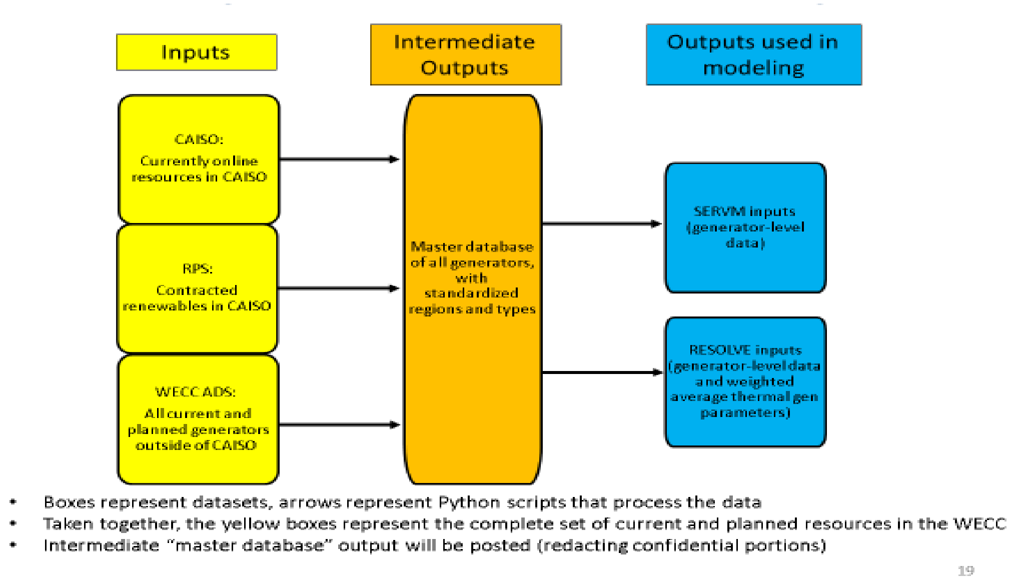
2. CAISO and LADWP Power Flow Models

To determine Minimum Local Generation scenario assumptions for generators to be preserved in PCM modeling, staff asked for power flow modeling to be performed by CAISO and LADWP and delivered to the CPUC in sufficient detail as to inform specific generating resource curtailment.

3. Electric Generation

Electric generators operating across the Western Electricity Coordinating Council (WECC) region are drawn from three main sources. For generators operating within the CAISO area, staff extracted information from the confidential CAISO Masterfile which lists operating parameters for all generating resources serving CAISO's electric market. For generators outside of the CAISO balancing area, all generation information including maximum capacity, online dates and operating parameters, is drawn from the WECC 2028 Anchor Data Set[12]. This dataset is intended to be used by agencies planning for the electric system into future years so that they can accurately assess the interactions of one balancing area with the rest of WECC.

Figure I - 2 Creating Master WECC-wide Generator List: Process Diagram




[12] The 2028 WECC Anchor Data Set Phase 2 V2.0 can be downloaded from this page: https://www.wecc.org/SystemStabilityPlanning/Pages/AnchorDataSet.aspx

4. Electric Demand Forecast and Hourly Profiles

   Forecasted electric demand is a core input into any electric system planning analysis. To create the Reference System Plan and for all the modeling performed for the Aliso proceeding, staff used the CEC's 2018 Integrated Energy Policy Report (IEPR) Update Forecast as a core input. CPUC modeling generally uses the mid-demand forecast from the IEPR forecast workbooks. CPUC's IRP planning models consider uncertainty by studying a range of weather scenarios drawn from 20 years of historical weather data (1998-2017).

5. Electric Demand Modifiers and Hourly Profiles

   The CEC's IEPR forecast must be translated into the range of inputs needed by the CPUC's IRP planning models, including demand forecasts and hourly electric demand profiles. There are also demand modifiers such as energy efficiency and behind-the-meter solar generation.

   To individually model demand modifiers, the IEPR demand forecast must be decomposed into constituent parts in terms of annual energy, peak impact, including any shifting effect and hourly profiles.

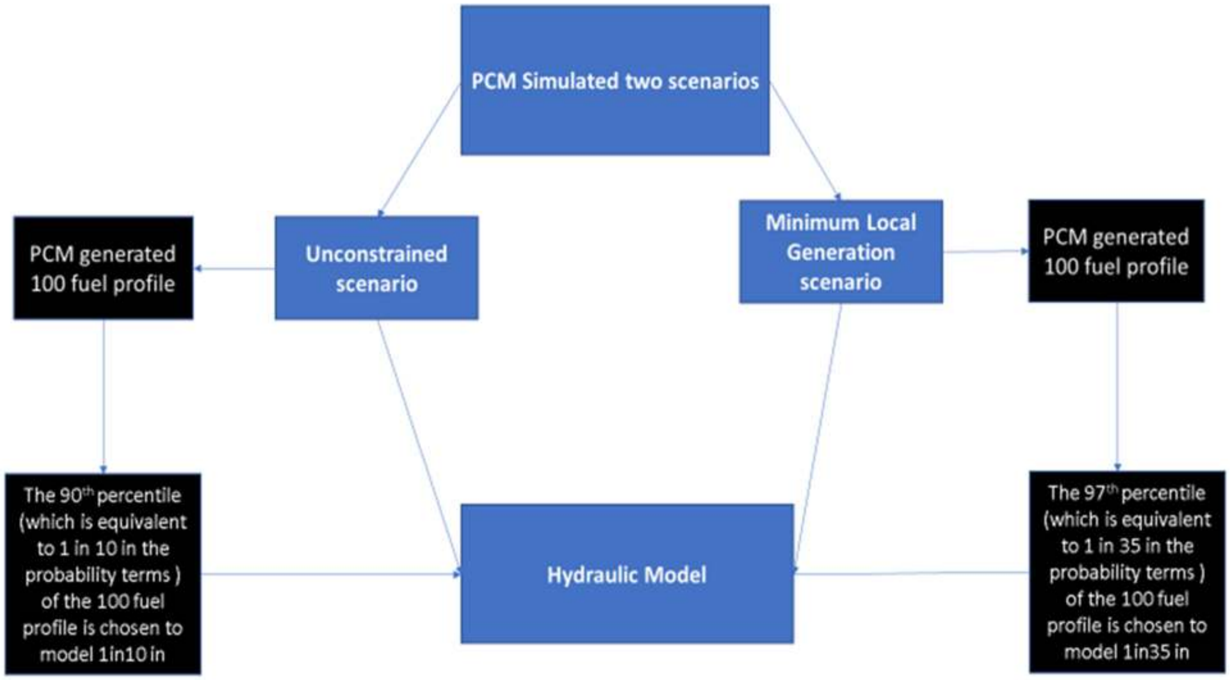
   Additional achievable energy efficiency (AAEE), time-of-use (TOU) rate effects, and light-duty electric vehicle (LDEV) load are each modeled individually with fixed hourly profiles. Behind-the-meter solar generation and behind-the-meter storage are modeled as resources with installed capacity. Other demand modifier components in the IEPR are left embedded in demand (other electrification, climate change, behind-the-meter combined heat and power, and load-modifying demand response).

## Hourly Gas Use Profiles

As stated in the introduction, the second purpose of performing PCM analysis was to develop hourly demand profiles for the 1-in-10 peak day and 1-in-35 extreme peak day hydraulic modeling scenarios. Staff followed the steps laid out in the Scenarios Framework to generate gas profiles for the Unconstrained and the MinLocGen scenarios.

To develop the Unconstrained scenario, staff generated 100 fuel burn profiles for each summer and winter study year. Staff modeled the entire month of September to represent summer electric and gas demand and supply, and the entire month of December to represent winter. Next, staff ordered and ranked the 100 profiles from the lowest to the highest fuel burn for each scenario. Then, for the Unconstrained scenario, the daily profile within the 90$^{th}$ percentile level of use out of all days in the month was input into the hydraulic model to mimic the 1-in-10 probability. Staff used fuel burn at the 97$^{th}$ percentile for the MinLocGen scenario to mimic the 1-in-35 probability. These steps are shown in Figure 1-3.

Figure I - 3 Process to Develop Gas Use Profiles




## Results

There were three main findings in the PCM results. Staff found:

1. The MinLocGen scenario produced significant degradation to reliability in all study years in Summer relative to the Unconstrainted scenario.
2. Electric production costs in the 2030 Minimum Local Generation scenario were approximately 3.3 percent or $121.3 million higher than in the Unconstrained Scenario.
3. Emissions slightly decreased in the Minimum Local Generation scenario in comparison to the Unconstrained scenario due to the inability to serve all electric demand.

## Reliability Results

Although the North American Electric Reliability Corporation (NERC) currently does not mandate a Loss of Load Expectation metric across all areas of North America, a LOLE metric is currently adopted in the majority of balancing authorities in North America, including several states in the Reliability First Corporation area of the Northeastern U.S.[13] A LOLE value of 0.1 refers to an expectation of one day with an event in 10 years. For details on the LOLE, refer to the Unified Resource Adequacy and Integrated Resource Plan Inputs and Assumptions discussed earlier. Staff considered the electric system sufficiently reliable if the probability weighted LOLE was less than or

[13] http://site.ieee.org/pes-rrpasc/files/2019/06/12-NERC-IEEE-LOLEWG-Meeting-2018.pdf, slide 8

equal to 0.1, which corresponds to about one day in 10 years where firm load (electric demand) must be shed to balance the grid. Row 2 in Table I– 2 displays staff's LOLE results in the CAISO area only. Staff have put the most work into calibrating results for the CAISO area in the IRP modeling and have usually shown results for the CAISO area, not the LADWP or IID areas. For that reason, comparisons here are made only to the CAISO area. The MinLocGen LOLE results of 2.42 in 2020, 0.68 in 2025, and 2.13 in 2030 are much higher than the acceptable level of 0.1. In the figure, green indicates acceptable LOLE results. Row 2 displays the Loss of Load Hours per year, Row 3 displays Loss of Load Hours per event, and Row 4 is Expected Unserved Energy.

The EUE results in Row 5 can be unpacked to better understand the implications. As shown in the table, the EUE rises from 19 megawatt hours (MWh) in the first Unconstrained scenario to 7,093 MWh in the MinLocGen scenario. The majority of the EUE MWh occurred between the hours of 6:00 to 9:00 PM in September. In the MinLocGen scenario, 6,800 MWh of the 7,093 MWh unserved occurred in September 2020. July and August 2020 did not see significant EUE increases because staff only applied the constraints to September.

The trend continues through 2025 and 2030, with approximately 3,600 MWh of unserved load in the MinLocGen scenario in September 2025 and 13,600 MWh in September 2030. In 2030, the EUE hours are spread between 5:00 and 10:00 PM because the increased penetration of solar generation shifts the peak demand an hour later into the evening. During the workshop, staff identified an error in modeling the MinLocGen scenario that caused a high LOLE in December 2030. The error was caused by curtailing more generation than was allowed given the CAISO and LADWP local capacity studies. In correcting that error, staff found that no study years showed LOLE in the winter months. LOLE caused by the MinLocGen scenario occurred only in September although hydraulic modeling overall demonstrated more significant reliability problems in the winter.

Table I- 2 Loss of Load Expectation Result in CAISO

| | 2022 | 2026 | 2030 | 2020 | 2025 | 2030 |
|---|---|---|---|---|---|---|
| **Reliability Metrics** | **Unconstrained** | | | **Minimum Local Generation** | | |
| **1. LOLE (expected outage events/year)** | 0.03 | 0.11 | 0.11 | 2.42 | 0.68 | 2.13 |
| **2. LOLH (hours/year)** | 0.04 | 0.25 | 0.26 | 5.14 | 1.63 | 5.39 |
| **3. LOLH/LOLE (hours/event)** | 1.29 | 2.24 | 2.37 | 2.13 | 2.41 | 2.54 |

| | | | | | | |
|---|---|---|---|---|---|---|
| **4. EUE (MWh)** | 19 | 292 | 598 | 7,093 | 3,061 | 14,165 |
| **5. Annual load (GWh)** | 246,957 | 252,862 | 255,838 | 241,932 | 251,927 | 255,830 |

## Energy Generation

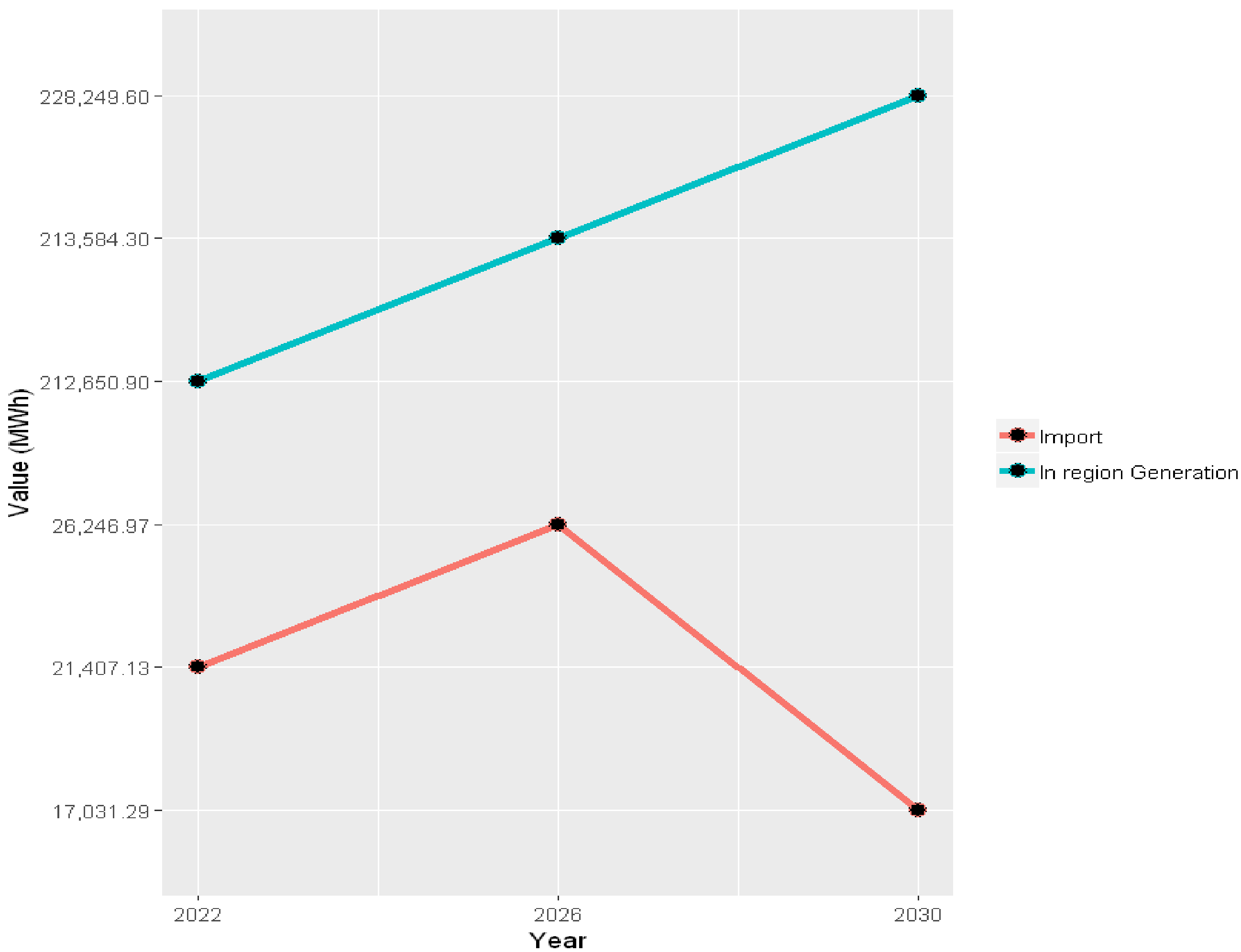
Results from the PCM modeling in SERVM show a comparison between CAISO area energy generation in the Unconstrained scenario and MinLocGen scenario in 2030. The MinLocGen scenario resulted in less in-region generation relative to the Unconstrained scenario because gas-fired electric generation was curtailed in September and December, which decreased overall generation to 224,664 gigawatt hours (GWh). Row 3 indicates that more imports into the CAISO are necessary, and there is a decrease in CAISO exports in Row 6 due to a decrease in CAISO-area generation. Other factors remain the same, such as electric demand in Row 4 and overall storage dispatch (as illustrated by net losses from storage and pumped hydro) in Row 7.

Table I- 3 CAISO Energy Generation and Demand Balance in 2030

| | 2030 | 2030 |
|---|---|---|
| **CAISO System Balance (GWh)** | **Unconstrained** | **Minimum Local Generation** |
| **1. In-region generation serving CAISO load, including behind the meter solar and excluding storage discharge** | 228,249 | 224,664 |
| **2. Non-Solar Load Modifiers (net effect of energy efficiency, electric vehicles and time of use rates)** | 15,848 | 15,855 |
| **3. Unspecified carbon-emitting imports netted hourly (in addition to northwest Hydro)** | 17,031 | 20,328 |
| **4. Load (not including net effects of Non-Solar Load Modifiers)** | 255,838 | 255,830 |
| **5. Non-PV Load Modifiers (net effect of AAEE, EV, TOU)** | 15,848 | 15,855 |
| **6. Unspecified carbon-emitting exports netted hourly** | 7,562 | 7,419 |
| **7. Battery and Pumped Storage Hydro losses (net of charge and discharge)** | 3,610 | 3,582 |
| **8. Curtailment** | 1,056 | 1,092 |

The need for more imports in the MinLocGen scenario creates a problem when considered along with the CPUC's adopted Reference System Plan. The Reference System Plan anticipates an increased reliance on in-state electric generation between 2022 and 2030 due to a trend of decreasing electricity imports into CAISO. As other areas outside of CAISO anticipate a transition away from fossil fuels, an increase in renewable penetration and retirement of a large percentage of coal generation, less generation will be available to support CAISO than in the past. This decrease is illustrated in Figure I- 4, which compares anticipated in-state electric generation with anticipated electric imports resulting from modeling the Unconstrained scenario in 2022, 2026, and 2030 and is a forecast of generation patterns likely in future years. The red line illustrates the electricity imports forecasted for 2022, 2026, and 2030 in the Unconstrained scenario. To compensate for the decrease in imports, in-basin generation is expected to increase to maintain electric reliability.

Figure I - 4 Decrease in Imports and Increased Reliance on In-State Generation




## Production Costs

Production costs equate to the total amount of variable costs in excess of fixed costs that are incurred in operating the electric generation system. In the PCM model, power plants are dispatched to meet hourly electric demand in the order needed to minimize total production costs. In the PCM model, five types of costs are included in total production costs for each power plant. Power plant costs are related to emissions permits, costs incurred to pay for fuel, costs related to starting up a power plant (not including the fuel burned to start) and any other variable operations and maintenance costs. In addition to these four types of production costs, costs for purchasing imported power and revenue for selling exported electricity are also calculated and totaled. All costs summarized in Table I-4 are in millions of dollars per year ($MM/yr) and correspond to year 2030. Differences in overall electric generation patterns between the Unconstrained scenario and the MinLocGen scenario lead to differences in types of costs incurred; the Unconstrained scenario includes less costs for purchasing imported power and more costs for electricity generated within the CAISO region. Because imported power is often less fuel and cost efficient, it costs more per unit. For that reason, the MinLocGen scenario leads to a 3.3 percent increase over the

Unconstrained scenario, or about $121 million higher total production costs even though not all electric demand is met.

Table I- 4 CAISO Production Cost in 2030 ($MM/year)

| | 2030 | 2030 |
|---|---|---|
| **CAISO Production Costs** | **Unconstrained** | **Minimum Local Generation** |
| **Emissions** | $718 | $680 |
| **Fuel** | $2,069 | $1,969 |
| **Startup** | $246 | $243 |
| **Variable Operations & Maintenance** | $69 | $67 |
| **Unspecified Imports** | $1,194 | $1,493 |
| **Unspecified Exports** | -$647 | -$680 |
| **Total Production Costs** | $3,652 | $3,774 |

## Fuel Burn and Emissions

Expected fuel burn by resource type is reported by the PCM model from hourly dispatch results. The results in, Rows 1 through 6, show that less fuel is burned for electric generation in the MinLocGen scenario in 2030. Some of the reduced generation is made up by imports and reciprocating engines also called internal combustion engine generators but there is less overall generation and fuel burn in the MinLocGen scenario. Reduced local generation results in reduced emissions from gas-fired generation in CAISO, although emissions from increased imports are not included in the total. Tables I -- 5 and I -- 6 only reflect fuel burn and emissions in the CAISO territory.

Table 1 – 5 Fuel Burn in 2030 (MMBtu)

| Category | Unconstrained | Minimum Local Generation |
|---|---|---|
| **1. CAISO_CCGT1** | 318,120,022 | 302,060,519 |
| **2. CAISO_CCGT2** | 43,192,377 | 42,198,899 |
| **3. CAISO_Peaker1** | 56,315,520 | 50,945,155 |
| **4. CAISO_Peaker2** | 38,806,375 | 38,014,431 |
| **5. Steam** | 0 | 0 |
| **6. Cogen** | 80,641,355 | 75,183,996 |
| **7. Internal Combustion Engine** | 938,143 | 1,136,177 |

Table 1 – 6 Emissions in 2030 (MMT of $CO_2$)

| Category | Unconstrained | Minimum Local Generation |
|---|---|---|
| **1. CAISO_CCGT1** | 16.88 | 16.03 |
| **2. CAISO_CCGT2** | 2.29 | 2.24 |
| **3. CAISO_Peaker1** | 2.99 | 2.7 |
| **4. CAISO_Peaker2** | 2.08 | 2.04 |
| **5. Steam** | 0 | 0 |
| **6. Biomass** | 0 | 0 |
| **7. Geothermal** | 0 | 0 |
| **8. Cogen** | 4.3 | 4.01 |
| **9. Nuclear** | 0 | 0 |
| **10. Internal Combustion Engine** | 0.05 | 0.06 |
| **Emissions total** | 28.6 | 27.08 |

## Hourly Gas Use Profiles

In addition to determining whether the Minimum Local Generation scenario leads to increased production costs or less reliability, PCM analysis is used to develop demand profiles at an hourly level for the 1-in-10 peak day and 1-in-35 extreme peak day hydraulic modeling scenarios.

To derive electric generation (EG) demand profiles, staff began with forecasts from the recently adopted Reference System Plan in the Integrated Resource Planning Proceeding. Using these forecasts in a PCM model, staff generated demand profiles for winter and summer fuel burn under 100 different study cases, representing 20 simulated weather years and five different levels of economic and demographic uncertainty. CPUC averaged the 90$^{th}$ percentile demand under each of these 100 cases to get the EG demand for the 1-in-10 modeling.

For the 1-in-35 year modeling, the month and study case with electric generation gas demand closest to the 97$^{th}$ percentile was selected. Within that month, the day of highest gas demand was selected, and the hourly fuel burn profiles from that day were extracted for each thermal power plant and imported into the hydraulic model. More information on gas demand profiles used in hydraulic modeling is given later in this paper.

## Conclusion

In conclusion, staff performed PCM modeling of the Unconstrained scenario and the MinLocGen scenario in accordance with what was described in the Scenarios Framework. Staff demonstrated the reliability and cost effects of implementing curtailments on the electric system and used those results to produce hourly gas demand profiles for hydraulic modeling. We demonstrated that curtailment such as required under an extreme 1-in-35 gas demand scenario would create significant reliability effects in the electric system and raise production costs due to less optimal resource dispatch.

Staff used the gas demand profiles generated by this PCM analysis taken from September and December calendar months to conduct hydraulic modeling on the 1-in-10 and 1-in-35 gas demand scenarios and completed that analysis also for presentation in various CPUC workshops. This concludes the modeling envisioned in Phase 2 of the proceeding by demonstrating the current state of the energy (both gas and electricity) system so we can begin to develop alternatives that may change the current system to one that can much more safely and reliably operate without the Aliso Canyon gas storage field.

# II. 1-in-10 Scenarios Modeling

## Overview

Pursuant to Senate Bill (SB) 380, the California Public Utilities Commission's (CPUC) Energy Division staff (staff) oversaw and performed hydraulic modeling to ascertain the ability of the current gas infrastructure system (system) to provide reliable gas service to gas customers, inclusive of a minimization in usage or elimination of the Aliso Canyon underground storage facility. The first three sets of modeling assessed whether the system could reliably serve different types of customers under different conditions (reliability assessment). These models focused on meeting demand for a single hypothetical peak day design. The fourth and final set of modeling assessed the feasibility of meeting demand across multiple days under a range of conditions (feasibility assessment). The reliability assessment consisted of 1) 1-in-10 peak design day analyses, 2) 1-in-10 peak design day sensitivity analyses, 3) 1-in-35 extreme peak design day analyses. These were followed by the feasibility assessment. Southern California Gas Company (SoCalGas) performed the 1-in-10 peak day design analysis and the 1-in-35 extreme peak day design, and ED staff and the Los Alamos National Laboratory (Los Alamos) obtained the SoCalGas model and replicated and analyzed the results. ED staff performed the two remaining analyses.

The 1-in-10 peak design day analysis modeled the SoCalGas system under peak day winter and summer high demand in the years 2020, 2025, and 2030 to determine electric and gas system reliability for the southern California region. Simulation results indicated that at least 520MMcfd of withdrawal capacity is needed from Aliso Canyon under baseline assumptions during the winter season of 2030 and more for the other two study years. The withdrawal capacity needed increased as the supplies from other storage fields decreased. The summer high demand day simulations indicated that Aliso Canyon may not be needed during the summer season.

Next, staff performed three sensitivity analyses on the winter 2030 1-in-10 peak design day analysis by adjusting storage inventory in the Honor Rancho, Playa del Rey, and La Goleta storage fields (collectively referred to as the non-Aliso fields). The winter 2030 base case modeled the non-Aliso fields at 90 percent inventory levels and resulted in a required Aliso Canyon withdrawal rate of 520 MMcfd. The sensitivities with non-Aliso field inventory levels of 70, 50, and 37 percent resulted in required Aliso Canyon withdrawal rates of 830, 1,010, and 1,160 MMcfd, respectively.

The 1-in-35 extreme peak design day analysis modeled the SoCalGas system under extreme peak day winter conditions in the years 2020, 2025, and 2030. Unlike the 1-in-10 peak design day standard, the 1-in-35 extreme peak design day standard allows for the curtailment of noncore customers, which includes electric generation customers. Staff, however, modeled the 1-in-35 extreme peak design standard under a minimum local generation scenario, wherein electric generators were allowed minimum use of gas only to preserve local reliability criteria. Under these conditions, the total gas demand was about 30 percent less than that of a 1-in-10 peak design day. The results of the 3 simulations indicated that Aliso Canyon may not be needed to meet the 1-in-35 reliability standard for any of 3 study years.

Lastly, staff determined whether the minimum Aliso Canyon inventory levels established in the 1-in-10 peak design day analyses were feasible. The feasibility assessment used a statistical methodology to assess if the monthly minimum storage targets throughout the SoCalGas system could be maintained throughout a study year. The feasibility assessment forecasted the daily gas demand for every day in the study year using monthly statistical distributions derived from a mix of known historical daily demand data and forecasted monthly averages from the California Gas Report 2018. The feasibility assessment provided res based on available interstate supplies ranging from 60 to 100 percent of the CalGEM approved inventory level (68.6 Bcf) for the Aliso Canyon facility.

Both the 1-in-10 peak design day reliability assessment and the feasibility assessment ascertain the need for the Aliso Canyon underground storage field. From a hydraulics standpoint, the role of Aliso Canyon is evidently two-fold. First, Aliso Canyon must maintain a certain minimum withdrawal capacity during the winter to maintain the reliability of the gas-electric system during a peak design day. The second role of Aliso Canyon is to actually "store" natural gas for when interstate supplies are scarce, whether due to upstream multi-state disturbances, production shortages, or pipeline outages, which enables the gas-electric system to sustain longer cold snaps. On the other hand, the reliability assessment of the 1-in-35 extreme peak day as well as the high demand summer day simulations indicate that Aliso Canyon may not needed to meet the demand on these days, though the demand on these days is generally about 50-75 percent of that on a 1-in-10 peak design day.

Results show that selecting a maximum Aliso Canyon inventory level should be based on consideration of several factors elucidated by the reliability and feasibility assessment results. These factors include weighing the risk of some level of curtailments, consideration of the Unbundled Storage Program, the economic impact of Aliso Canyon's inventory, and the likelihood of average pipeline capacity and utilization increasing. Given these uncertain factors, staff recommends choosing among three potential maximum allowable inventory levels, which vary by percentage of the maximum inventory of 68.6 Bcf authorized by CalGEM: 100 percent (or 68.6 Bcf), 80 percent (or 54.88 Bcf), and 60 percent (or 41.16 Bcf). The results are summarized in Table V-2.

## Background on 1-in-10 Modeling

Following the October 23, 2015 gas leak at Aliso Canyon, on January 6, 2016, Governor Brown ordered SoCalGas to maximize withdrawals from Aliso Canyon to reduce the pressure in the facility.[14] The CPUC subsequently required SoCalGas to leave 15 billion cubic feet (Bcf) of working gas in the facility that could be withdrawn to maintain reliability. On May 10, 2016, Senate Bill (SB) 380[15] was approved. Among other things, the bill:

1. Prohibited injection into Aliso Canyon until a safety review was completed and certified by the Division of Oil, Gas, and Geothermal Resources (DOGGR)[16] with concurrence from the CPUC;
2. Required DOGGR to set the maximum and minimum reservoir pressure;
3. Charged the CPUC with determining the range of working gas necessary to ensure safety and reliability and just and reasonable rates in the short term; and
4. Required the CPUC to open a proceeding to determine the feasibility of minimizing or eliminating use of Aliso over the long term while still maintaining energy and electric reliability for the region.

On February 9, 2017, pursuant to Senate Bill 380, the CPUC opened Investigation (I.) 17-02-002 to determine the long-term feasibility of minimizing or eliminating the use of the facility while still maintaining energy and electric reliability for the Los Angeles region at just and reasonable rates. In Phase 1 of I.17-02-002, ED staff engaged in an extensive stakeholder process to develop models (including assumptions, scenarios and inputs) to evaluate the effects of minimizing or eliminating the use of Aliso Canyon. That phase culminated in an Assigned Commissioner and Administrative Law Judge's Ruling adopting the Scenarios Framework, issued on January 4, 2019.[17] The adopted Scenarios Framework set forth the roadmap for three modeling streams to be completed in Phase 2 of the investigation—hydraulic modeling, production cost modeling, and economic modeling. The CPUC subsequently issued the Hydraulic Modeling Clarifications document on May 27, 2020. Staff presented the results of the modeling in workshops on June 20, 2019; November 13, 2019; July 28, 2020; and October 15, 2020. Together these analyses present a picture of Aliso Canyon's impact on costs and reliability. The results of the hydraulic modeling studies outlined in the Scenarios Framework are presented in this report.

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[14] https://www.gov.ca.gov/2016/01/06/news19263/
[15] Statues of 2016, chapter 14.
[16] DOGGR has since been renamed. It is now the California Geologic Energy Management Division or CalGEM.
[17] The (I.)17-02-002 Scenarios Framework can be found here: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M258/K116/258116686.PDF.

## Overview of Demand, Supply, Methodology

### 1. Demand

Gas demand falls into three categories: 1) core (residential, commercial, industrial, municipal, and wholesale); 2) noncore, non-electric generation (commercial, industrial, refinery, and enhanced oil recovery); and 3) noncore, electric generation (EG). SoCalGas sells gas to core customers, whereas noncore customers buy their gas from other sources and SoCalGas delivers it. All six scenarios used core and noncore, non-EG demand volumes obtained from the 1-in-10 peak design day and the summer high sendout day in the 2018 California Gas Report (CGR). EG demand profiles were calculated by Energy Division staff and compared with SoCalGas EG demand profiles.

To derive EG demand profiles, staff began with forecasts from the recently adopted Reference System Plan (RSP) in the Integrated Resource Planning (IRP) Proceeding. Using the SERVM Production Cost Modeling software, staff used these forecasts to generate demand profiles for winter and summer fuel burn under 100 different sets of assumptions, representing 20 simulated weather years and 5 different values representing uncertainty in economics and demographics. CPUC averaged the 90$^{th}$ percentile demand under each of these 100 cases to get the CPUC EG demand.

Scenario S01 used SoCalGas electric generation forecasts from the California Gas Report 2018 and corresponding hourly profiles while scenarios S02-S06 used the CPUC EG demand forecasts and hourly profiles since SoCalGas began working on S01 before staff had the EG demand forecasts ready.

Looking to the future, significant investments in renewable generation are expected to decrease California's reliance on gas-fired electric generation. However, there are several factors that are expected to push in the other direction. Factors increasing demand for in-state, gas-fired electric generation include:

- Decreasing electricity imports as other states increase their use of renewables and retire their coal and gas generation while increasing demand due to population growth;
- The retirement of Diablo Canyon; and
- Reduced solar generation in winter peak hours.

As per the Scenarios Framework document and the subsequent Clarification document, staff decided to look into seasonal scenarios rather than monthly ones for all 3 study years. This resulted in only six scenarios, three for the winter season peak design day, and three for the summer season. The following table details the gas demand in each category for all six scenarios.

Table II- 1 Demands for Simulations 01-06

| Demand | S01 Winter 2020 MMcfd[18] | S02 Summer 2020 MMcfd | S03 Winter 2025 MMcfd | S04 Summer 2025 MMcfd | S05 Winter 2030 MMcfd | S06 Summer 2030 MMcfd |
|---|---|---|---|---|---|---|
| Core | 3,285 | 808 | 3,170.7 | 808 | 3,034 | 808 |
| Noncore, Non-EG | 654 | 718.6 | 689.2 | 700.8 | 664.6 | 687 |
| Noncore, EG | 1,048 | 1,030.2 | 900 | 1,109.6 | 1,122.6 | 1,180 |
| **Total Demand** | **4,987** | **2,556.8** | **4,759.9** | **2,618.4** | **4,821.2** | **2,675** |

The following table compares the CPUC gas demands to those of the 2018 California Gas Report.

Table II- 2 Comparison of CPUC Forecasted Gas Demands to 2018 California Gas Report Forecasted Gas Demands

| | S01 Winter 2020 MMcfd | S02 Summer 2020 MMcfd | S03 Winter 2025 MMcfd | S04 Summer 2025 MMcfd | S05 Winter 2030 MMcfd | S06 Summer 2030 MMcfd |
|---|---|---|---|---|---|---|
| CGR 2018 Demand | 4,987 | 3,324 | 4,719 | 2,932 | 4,519 | 2,876 |
| CPUC Demand | 4,876 | 2,557 | 4,760 | 2,619 | 4,822 | 2,675 |
| Difference | -111 | -767 | +41 | -313 | +303 | -201 |

A Ruling was filed in March 2020 providing updates on the hydraulic modeling reliability scenarios and sensitivity cases.[19] In addition, a clarification document summarizing most of the assumptions was posted in May.[20]

## 2. Supply

The six modeling scenarios assumed 85 percent receipt point utilization of the nominal zonal capacities for the Northern and Southern Zones and 100 percent for the Wheeler Ridge Zone, which total 1,590 MMcfd, 1,210 MMcfd, and 765 MMcfd, respectively for a total of 3,565 MMcfd. For unplanned outages, the modeling scenarios assumed Line 3000, Line 235-2, and Line 4000 were operating at reduced pressures but not entirely out of service.

Anticipating that some simulations may be redundant and may not provide additional information, staff made modifications to the scenarios such as the addition or removal of outages. For example, if a scenario meets all success criteria (such as S02 Summer 2020), staff began an iterative process of changing the scenario by removing pipeline capacity or increasing outages in order to stress the system to find the point at which Aliso Canyon would be needed. Winter 2030 scenario S05 is the

[18] MMcfd = million cubic feet per day.
[19] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M328/K765/328765817.PDF
[20] https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2020/FurtherHydraulicModelingClarifications-05272020.pdf

only scenario that allowed the usage of Aliso Canyon withdrawals to determine the minimum amount needed for reliability. Summer 2030 scenario S06 excluded the use of Honor Rancho as another possible outage to stress the system further than S02 and S04.

Unless otherwise noted, underground storage inventory levels are assumed to be at 90 percent of the maximum inventory, and withdrawal capacities are calculated at the corresponding point on each field's maximum withdrawal curve. In summer scenarios S04 and S06, the inventories were assumed to be at 70 percent of the maximum inventory, to stress the system. In addition, in S06, Honor Rancho was assumed to be shut in.

The following table details the pipeline receipts and maximum storage withdrawals available for each scenario based on the assumed inventory level.

Table II- 3 Gas Pipeline Receipt Points and Maximum Withdrawal Rates Allowed from Storage Fields for Scenarios S01 through S06

| Receipt Points | S01 Winter 2020 MMcfd | S02 Summer 2020 MMcfd | S03 Winter 2025 MMcfd | S04 Summer 2025 MMcfd | S05 Winter 2030 MMcfd | S06 Summer 2030 MMcfd |
|---|---|---|---|---|---|---|
| Cal Producers | 70 | 70 | 70 | 0 | 70 | 0 |
| Wheeler Ridge | 765 | 765 | 765 | 600 | 765 | 600 |
| | | | | | | |
| Blythe Ehrenberg | 833 | 750 | 728.5 | 920 | 980 | 920 |
| Otay Mesa | 195.5 | 50 | 300 | 0 | 50 | 0 |
| Total Southern Zone | 1,028.5 | 800 | 1,028 | 920 | 1,030 | 920 |
| | | | | | | |
| Kramer Junction | 276.25 | 550 | 420 | 700 | 420 | 700 |
| North Needles | 340 | 300 | 430 | 0 | 430 | 0 |
| South Needles | 446.25 | 200 | 400 | 0 | 400 | 0 |
| Total Northern Zone | 1,062.5 | 1,050 | 1,250 | 700 | 1,250 | 700 |
| | | | | | | |
| Total Pipeline Receipts | 2,926 | 2,685 | 3,113.5 | 2,220 | 3,115 | 2,220 |
| | | | | | | |
| Non-Aliso W/D | 1,330 | 1,329 | 1,329 | 1,116 | 1,329 | 444 |
| Honor Rancho Max W/D | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| La Goleta Max W/D | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Playa Del Rey Max W/D | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Aliso Max W/D | 0 | 0 | 0 | 0 | 1,265 | 0 |
| Storage Max W/D | 1,330 | 1,329 | 1,329 | 1,116 | 2,594 | 444 |
| Total Available Supplies | 4,256 | 4,014 | 4,442 | 3,336 | 5,709 | 2,664 |

The withdrawal rates shown in the table are the maximum withdrawal rates available based on the inventory assumptions of a certain scenario. In all winter scenarios, this maximum available withdrawal rate of the non-Aliso fields has been used in the transient simulation.

In the scenario using Aliso Canyon, the maximum available Aliso Canyon withdrawal rate is based on 90 percent inventory level. However, the actual required withdrawal rate is an *outcome* of the simulation (to maintain the pressures above the minimum operating pressures). Had the simulation required more than the maximum allowed withdrawal rate from Aliso Canyon, then this simulation would be a failed simulation despite the use of Aliso Canyon.

## 3. Methodology

Transient simulations for a 24-hour period are required to evaluate the impacts of time-varying loads on linepacks and pressures. Therefore, the assumptions of all six scenarios that have been described in the previous section have been translated into input data for each simulation. Each scenario was translated into one simulation to be run in the modeling software. For each scenario, one simulation was run. Hence, the results of simulation S01 correspond to the inputs and assumptions of scenario S01. Sensitivities on scenario S05 Winter 2020 were performed and will be shown in a later section. To run a 24-hour transient simulation, the following input data must be imported into the modeling software:

1. Pipeline infrastructure (pipes lengths, diameters, and roughness) and topology
2. Compressors data (primarily maximum horsepower, efficiency, and set pressures)
3. Valves and regulators data (loss coefficients, set pressures, and capacities)
4. Daily demand for each node (a node can contain multiple customer types)
5. Hourly demand profile for each node
6. Pressure and flowrate at supply nodes (interstate and storage if used)
7. Pipeline pressure boundaries (i.e., maximum & minimum operating pressures)

Energy Division staff calculated hourly electric generation demands for the model which were used as inputs for each simulation run. These hourly load profiles were guided by a CPUC production cost model that predicts electricity loads for summer and winter days in 2020, 2025, and 2030. Each winter scenario represented a peak demand day (1-in-10 years) with only unplanned (unscheduled) outages (i.e. no planned outages were assumed or included).

Pipeline outages were incorporated as pressure reductions. For example, a pipeline that is normally rated at 800psig MOP was allowed to reach a maximum of 600psig if that pipeline is operating at that reduced pressure. Different pressure reductions result in different flow capacities. Both rated and reduced pressures are confidential information and hence not shown in this report.

Synergi Gas is one of the few software packages used by the natural gas industry to run steady and transient pipeline flow simulations. The original model was developed by the Capacity Planning Group in SoCalGas. To provide direct oversight of SoCalGas hydraulic modeling, both Energy

Division and Los Alamos staff initiated efforts to develop in-house capability for hydraulic modeling using Synergi Gas.

Synergi Gas uses the well-known method of characteristics to solve the transient equations of flow of natural gas in pipelines. Synergi Gas slow transient scheme incorporates industry-standard assumptions to decrease the computational cost of the simulations. The Synergi model takes inputs from the beginning of the day, simulates the gas flowing through the system and the demand pattern throughout the day, calculates the linepack, and shows whether pressures are within acceptable ranges. Each simulation was evaluated by SoCalGas engineers for successful solves and verified by Energy Division staff and Los Alamos National Lab analysts.

## What Constitutes a Successful Simulation?

There are four criteria for a successful simulation. A simulation fails if any one of the four following criteria is ***not met***:

1. The pipeline pressures are above the minimum operating pressures (MINOP) at all locations for all times during the 24-hour time period.
2. The pipeline pressures are below the maximum operating pressures (MOP) at all locations for all times during the 24-hour time period.
3. Linepack is recovered (returned to initial values) at the end of the 24-hour time period.
4. All facilities (storage, compressors, regulators, valves) are operated within their capacities.

## Overview of Results

## Which Simulations Succeeded and Which Failed?

While the Scenarios Framework document[21] established firm assumptions on all six scenarios, Energy Division staff approach to the supplies assumptions changed once the winter and summer electric generation demand forecasts were obtained from the production cost modeling (produced by SERVM). When the scenarios framework was published, it was expected that natural gas demand will decline consistently during the 2020-2030 period for both the winter and summer seasons. However, the production cost modeling showed that summer demand for all three study years is comparable, while the winter demand decreased in 2025, and increased back in 2030.

Simulating three study seasons with similar gas demand, which is the case for the summer season, seemed redundant. Therefore, Energy Division staff adopted the following approach; if the simulation of a certain scenario succeeds, then increase the stress on the pipeline-storage system in the next scenario. This could be achieved by adding outages, reducing the inventory level in the storage fields, or reducing the interstate supplies. This was the approach for the summer seasons of 2020, 2025, and 2030, where S02 succeeded, so S04 was stressed (lower inventory and supplies), which also succeeded, so S06 was stressed even more, which caused S06 to marginally fail without

[21] The (I.)17-02-002 Scenarios Framework can be found here: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M258/K116/258116686.PDF.

the use of Aliso Canyon. This approach provides more insight to the demand vs. supply balance and when Aliso would provide benefits to the reliability of the system.

For the winter seasons, both S01 and S03 failed with the use of Aliso Canyon, so the approach is to decrease the stress on the system by adding Aliso Canyon (as per the scenarios framework). Reducing the stress could have also been implemented by increasing the receipt point capacity beyond 85 percent, though historical data does not support it. The table below shows that all the winter simulations failed, and the summer 2030 simulation marginally failed due to increased outages (stress) on the system.

Table II- 4 Simulation Results

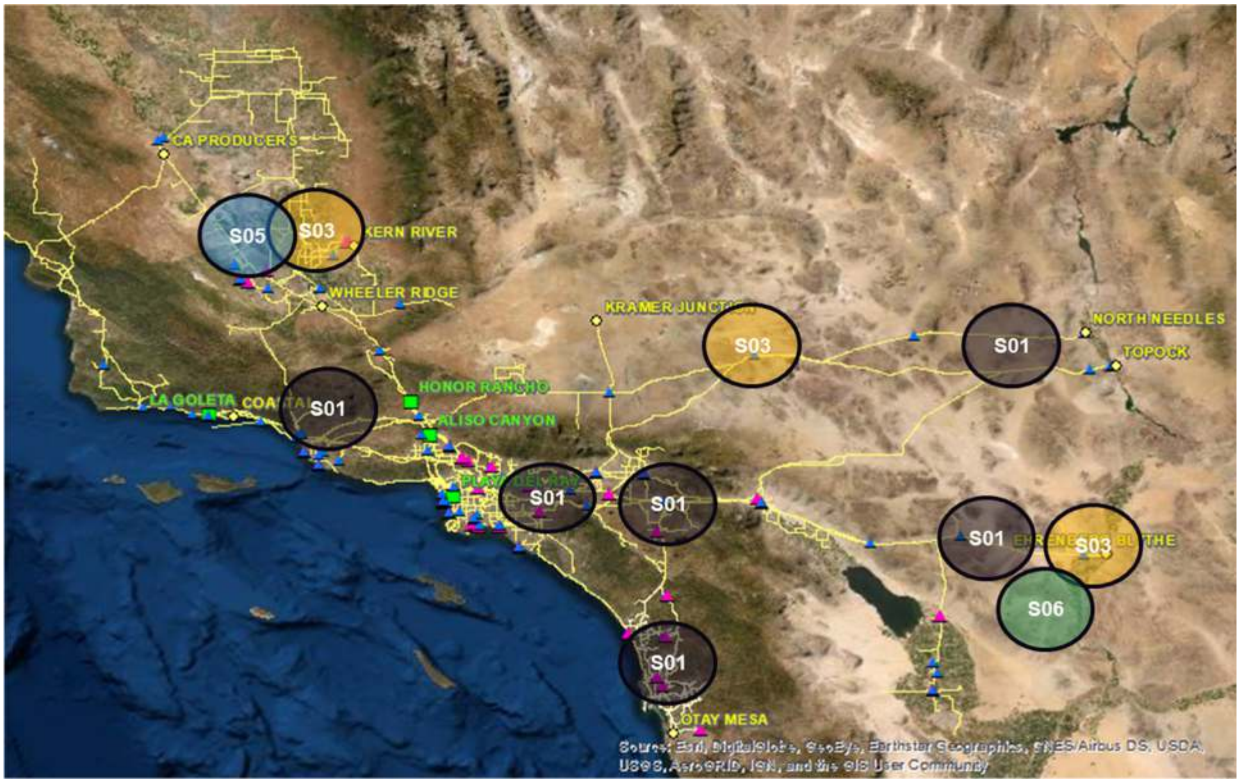
| | S01 Winter 2020 MMcfd | S02 Summer 2020 MMcfd | S03 Winter 2025 MMcfd | S04 Summer 2025 MMcfd | S05 Winter 2030 MMcfd | S06 Summer 2030 MMcfd |
|---|---|---|---|---|---|---|
| Demand | 4,987 | 2,556.8 | 4,759.9 | 2,618.4 | 4,821.2 | 2,675 |
| Pipeline Supply | 2,926 | 2,685 | 3,113.5 | 2,220 | 3,115 | 2,220 |
| Max. Withdrawal | 1,330 | 1,329 | 1,329 | 1,116 | 2,594 | 444 |
| Max. Injection | 368 | 368 | 368 | 442 | 368 | 191 |
| Pressures Above MINOP[22]? | NO | YES | NO | YES | NO | YES |
| Pressures Below MOP[23]? | YES | YES | YES | YES | YES | YES |
| Linepack Recovered? | NO | YES | NO | YES | YES | NO |
| Facilities Operated Within Capacities? | YES | YES | YES | YES | YES | YES |

## Where Did System Pressures and Linepack Fail in Simulations 01, 03, 05, and 06?

The map below shows the areas of failure for Simulations S01, S03, S05, and S06. Simulations S01 and S03 had both linepack and pressure failures. Simulation S05 had a pressure failure at the boundary of the system, and Simulation 06 had a linepack failure in the Southern Zone.

[22] MINOP is the minimum allowable pressure required to meet the demand in a given area or pipeline section
[23] MOP is the maximum operating pressure for a given pipeline

Figure II - 1 Locations of Linepack and Pressure Failures for Simulations 01, 03, 05, 06



# Scenarios Details and Simulations Results

## 1. Scenario S01 2020 Winter Peak (1-in-10)

| Demands | S01 Winter 2020 MMcfd |
|---|---|
| Core | 3,285 |
| Noncore, Non-EG | 654 |
| Noncore, EG | 1,048 |
| **Total Demand** | **4,987** |

| Receipt Points | S01 Winter 2020 MMcfd |
|---|---|
| | |
| Cal Producers | 70 |
| Wheeler Ridge | 765 |
| Blythe Ehrenberg | 833 |
| Otay Mesa | 195.5 |
| Total Southern Zone | 1,028.5 |
| | |
| Kramer Junction | 276.25 |
| North Needles | 340 |
| South Needles | 446.25 |
| Total Northern Zone | 1,062.5 |
| | |
| Total Pipeline Receipts | 2,926 |
| | |
| Non-Aliso W/D | 1,330 |
| Honor Rancho Max W/D | [redacted] |
| Goleta Max W/D | [redacted] |
| PDR Max W/D | [redacted] |
| Aliso Max W/D | 0 |
| Storage Max W/D | 1,330 |
| | |
| Total Available Receipts | 4,256 |

Simulation S01 for winter 2020 failed because the total forecasted demand of 4,987 MMcfd exceeded the total combined pipeline and storage receipts of 4,256 MMcfd. This resulted in minimum pressure violations and unrecoverable linepack.

The results of simulation S01 showed that the total linepack loss was around [redacted] MMcf. Linepack was lost in all the following zones: Southern, Northern, Coastal, LA Basin, San Diego and the San Joaquin Valley.

Pressure failures occurred inside and outside the LA Loop. All subsystems were impacted. The lowest pressures occurred in the South Basin, Orange County, and San Diego areas as well as the city-gates.

Storage withdrawals for the non-Aliso fields were modeled at their near max capacities for the full 24 hours for simulation S01.

The Southern Zone receipts of 1,028.5 MMcfd represent an 85 percent utilization factor of the 1,210 MMcfd nominal zonal capacity. The Northern Zone receipts of 1,062.5 represent an 85 percent utilization factor of 1,250 MMcfd, which is the operating capacity of the Northern Zone due to the partial outages of Lines 3000, 235-2, and 4000.

City gates set pressures were increased at time=18 in an effort to keep the pressure above MINOP in the Los Angeles Basin, but the effort ultimately failed and the city-gates were closed to preserve the Southern System pressures.

## 2. Scenario S02 2020 Summer High Demand

| Demands | S02 Summer 2020 MMcfd |
|---|---|
| Core | 808 |
| Noncore, Non-EG | 718.6 |
| Noncore, EG | 1,030.2 |
| **Total Demand** | **2,556.8** |
| Receipt Points | S02 Summer 2020 MMcfd |
| Cal Producers | 70 |
| Wheeler Ridge | 765 |
| Blythe Ehrenberg | 750 |
| Otay Mesa | 50 |
| Total Southern Zone | 800 |
| | |
| Kramer Junction | 550 |
| North Needles | 300 |
| South Needles | 200 |
| Total Northern Zone | 1,050 |
| | |
| Total Pipeline Receipts | 2,685 |
| | |
| Non-Aliso W/D | 1,329 |
| Honor Rancho Max W/D | [redacted] |
| Goleta Max W/D | [redacted] |
| PDR Max W/D | [redacted] |
| Aliso Max W/D | 0 |
| Storage Max W/D | 1,329 |
| | |
| Total Available Receipts | 4,014 |

Simulation S02 for summer 2020 was successful due to the available supplies of 4,014 MMcfd being more than enough to meet the forecasted demand of 2,557 MMcfd.[24]

In simulation S02, system pressures were maintained below the maximum operating pressures and above the minimum operating pressures. Linepack was recovered in all subsystems, and facilities operated within their capacities.

Withdrawals from storage were not needed in this simulation as pipeline supplies alone were able to meet the forecasted demand. This scenario included injections into Playa Del Rey, Honor Rancho, and La Goleta storage fields.

Compressors, regulators, and city-gates were adjusted during the 24-hour period to maintain pressures within limits given the variable demand throughout the simulation.

[24] The actual maximum sendout for summer 2020 (April-October) was 3,196 MMcfd, significantly higher than the forecast. Additionally, there were 26 days in summer 2020 that exceeded the high demand forecast of 2,557 MMcfd.

### 3. Scenario S03 2025 Winter Peak (1-in-10)

| Demands | S03 Winter 2025 MMcfd |
|---|---|
| Core | 3,170.7 |
| Noncore, Non-EG | 689.2 |
| Noncore, EG | 900 |
| **Total Demand** | **4,759.9** |
| Receipt Points | S03 Winter 2025 MMcfd |
| Cal Producers | 70 |
| Wheeler Ridge | 765 |
| Blythe Ehrenberg | 728.5 |
| Otay Mesa | 300 |
| Total Southern Zone | 1,028 |
| | |
| Kramer Junction | 420 |
| North Needles | 430 |
| South Needles | 400 |
| Total Northern Zone | 1,250 |
| | |
| Total Pipeline Receipts | 3,113.5 |
| | |
| Non-Aliso W/D | 1,329 |
| Honor Rancho Max W/D | [redacted] |
| Goleta Max W/D | [redacted] |
| PDR Max W/D | [redacted] |
| Aliso Max W/D | 0 |
| Storage Max W/D | 1,329 |
| | |
| Total Available Receipts | 4,442 |

Simulation S03 for winter 2025 failed because the total forecasted demand of 4,760 MMcfd exceeded the total available supply of 4,442 MMcfd. This resulted in pressure violations and unrecoverable linepack.

The results of simulation S03 showed a total linepack loss of around [redacted] MMcf. Linepack was not recovered in the Northern Zone or the Southern Zone.

The lowest pressures occurred in the San Joaquin Valley, Blythe and Line 4000. The pressure failures mainly occurred at the boundaries of the system, in the San Joaquin Valley, mainly because the city-gates were kept open to maintain the pressures in the LA Basin. Pressures in the LA Basin stayed above the minimum operation pressure, so no additional operational actions were needed there. However, pressures failed at the boundaries of the system.

Storage withdrawals for the non-Aliso fields were modeled at near maximum capacities for the full 24 hours for simulation S03.

The Southern Zone receipts of 1,028 MMcfd represent an 85 percent utilization factor of the 1,210 MMcfd nominal capacity. The Northern Zone receipts of 1,250 represent an 85 percent utilization factor of 1,590 MMcfd (which yields 1,351.5MMcfd) plus the additional partial outages of Lines 3000, 235-2, and 4000 (which discounts another 101.5MMcfd leading to 1,250MMcfd of available supplies in the Northern Zone). One stakeholder argued that the outages on the Northern System result in a loss of capacity of 340MMcfd (1,590-1,250=340MMcfd). However, if these outages are removed, the capacity increases only 101.5MMcfd, taking into account the 85 percent utilization factor.

Compressors, regulators, and city-gates were set at the start of the simulation to keep the LA Basin above its minimum operating pressure.

## 4. Scenario S04 2025 Summer High Demand

| Demands | S04 Summer 2025 MMcfd |
|---|---|
| Core | 808 |
| Noncore, Non-EG | 700.8 |
| Noncore, EG | 1,109.6 |
| **Total Demand** | **2,618.4** |

| Receipt Points | S04 Summer 2025 MMcfd |
|---|---|
| Cal Producers | 0 |
| Wheeler Ridge | 600 |
| Blythe Ehrenberg | 920 |
| Otay Mesa | 0 |
| Total Southern Zone | 920 |
| | |
| Kramer Junction | 700 |
| North Needles | 0 |
| South Needles | 0 |
| Total Northern Zone | 700 |
| | |
| Total Pipeline Receipts | 2,220 |
| | |
| Non-Aliso Max W/D | 1,116 |
| Honor Rancho Max W/D | [redacted] |
| Goleta Max W/D | [redacted] |
| PDR Max W/D | [redacted] |
| Aliso Max W/D | 0 |
| Storage Max W/D | 1,116 |
| | |
| Total Available Receipts | 3,336 |

Scenario S04 has a demand that is only slightly higher than scenario S02 (61.6 MMcfd). Had the same assumptions used in scenario S02 been used in scenario S04, simulation S04 would likely succeed without the use of Aliso Canyon. Therefore, staff decided to stress the summer system by decreasing the interstate receipts and the inventory levels in the non-Aliso fields. The inventory levels in the non-Aliso fields were decreased to 70 percent, while the available supplies were decreased to 400 MMcfd below the demand, an amount equal to one of the worst summer forecast errors (difference between forecast and sendout) in the past two years . California production was also assumed to have declined to zero.

Despite these stresses, simulation 04 for summer 2025 was successful due to the available supplies of 3,336 MMcfd being more than enough to meet the demand of 2,618 MMcfd.

In Simulation 04, system pressures were maintained below the maximum operating pressure and above the minimum operating pressure. Linepack was recovered in all subsystems, and facilities operated within their capacities.

Storage withdrawals were necessary due to the fact that pipeline receipts were not enough to meet total demand. Withdrawals from Honor Rancho and Playa del Rey were necessary to meet the variable demand starting at time=12. Honor Rancho withdrawals were needed at a withdrawal rate of 300 MMcfd for hours 12 through 30. Playa del Rey withdrawals were needed at its maximum withdrawal rate of 247 MMcfd for hours 13 through 30.

Compressors, regulators, and city-gates were adjusted during the 24-hour period to maintain pressures within limits given the variable demand throughout the simulation.

## 5. Scenario S05 2030 Winter Peak (1-in-10)

| Demands | S05 Winter 2030 MMcfd |
|---|---|
| Core | 3034 |
| Noncore, Non-EG | 664.6 |
| Noncore, EG | 1,122.6 |
| **Total Demand** | **4,821.2** |
| Receipt Points | S05 Winter 2030 MMcfd |
| Cal Producers | 70 |
| Wheeler Ridge | 765 |
| Blythe Ehrenberg | 980 |
| Otay Mesa | 50 |
| Total Southern Zone | 1,030 |
| | |
| Kramer Junction | 420 |
| North Needles | 430 |
| South Needles | 400 |
| Total Northern Zone | 1,250 |
| | |
| Total Pipeline Receipts | 3,115 |
| | |
| Non-Aliso W/D | 1,329 |
| Honor Rancho Max W/D | [redacted] |
| Goleta Max W/D | [redacted] |
| PDR Max W/D | [redacted] |
| Aliso Max W/D | 1,265 |
| Storage Max W/D | 2,594 |
| | |
| Total Available Receipts | 5,709 |

Scenario S05 for winter 2030 allowed the usage of the Aliso Canyon Storage Facility in order to determine a minimum withdrawal amount necessary to maintain the system pressures above the minimum operating pressures.

However, Simulation S05 failed marginally due to low pressures in the San Joaquin Valley. The simulation showed that this failure can't be resolved by increasing storage withdrawals or interstate supplies. This is because the pressures were maintained at the maximum operating pressure upstream of the regulators yet failed to maintain downstream pressure above the minimum operating pressures.  It was therefore concluded that no further operational actions could have resolved this failure. SoCalGas will investigate the San Joaquin Valley and determine whether a system improvement is required. All winter simulations (S01, S03, and S05) failed to maintain the pressures in the San Joaquin Valley with or without Aliso Canyon. However, unlike S01 and S03, this failure is the only cause of failure in S05. The San Joaquin valley pressures were sustained in the summer simulations due a combination of lower demand and different hourly load profiles of core customers.

The results of Simulation 05 showed that pressures were maintained above the minimum operating pressures in all other locations, and linepack was recovered. The lowest pressure occurred in the San Joaquin Valley near the boundary of the system.

Storage withdrawals for the non-Aliso fields were modeled at near maximum capacities for the full 24 hours for Simulation 05. Storage withdrawals from Aliso Canyon were necessary at a rate of 520 MMcfd, for hours 6 through 24 in order to meet the forecasted demand.[25]

Southern Zone receipts of 1,030 MMcfd represent an 85 percent utilization factor of the 1,210 MMcfd nominal capacity. The Northern Zone receipts of 1,250 represent an 85 percent utilization factor of 1,590 MMcfd plus the additional partial outages of Lines 3000, 235-2, and 4000.

Compressors, regulators, and city-gates were adjusted during the 24-hour period to maintain pressures within limits given the variable demand throughout the simulation. Once Aliso Canyon withdrawals began, city-gate pressures were modified to balance the majority of the system.

[25] https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2020/Session%203%20SB380July28workshop_LANL_slide%20deck-final.pdf

## 6. Scenario S06 2030 Summer High Demand

| Demands | S06 Summer 2030 MMcfd |
|---|---|
| Core | 808 |
| Noncore, Non-EG | 687 |
| Noncore, EG | 1,180 |
| **Total Demand** | **2,675** |
| Receipt Points | S06 Summer 2030 MMcfd |
| Cal Producers | 0 |
| Wheeler Ridge | 600 |
| Blythe Ehrenberg | 920 |
| Otay Mesa | 0 |
| Total Southern Zone | 920 |
| | |
| Kramer Junction | 700 |
| North Needles | 0 |
| South Needles | 0 |
| Total Northern Zone | 700 |
| | |
| Total Pipeline Receipts | 2,220 |
| | |
| Non-Aliso W/D | 444 |
| Honor Rancho Max W/D | [redacted] |
| Goleta Max W/D | [redacted] |
| PDR Max W/D | [redacted] |
| Aliso Max W/D | 0 |
| Storage Max W/D | 444 |
| | |
| Total Receipts | 2,747 |

Since the previous two summer simulations were both successful, it was decided that scenario S06 for summer 2030 would stress the summer system further. This was achieved by assuming that the Honor Rancho storage facility is undergoing a shut-in and is out-of-service, and assuming that California production has declined to zero. To further stress the system, storage withdrawals for the Playa del Rey and La Goleta storage fields were modeled at 70 percent inventory levels for the full 24 hours.

Simulation S06 failed marginally due to linepack loss in the Southern Zone. In Simulation S06, linepack loss was around [redacted] MMcf. Pressures were maintained above the minimum operating pressures in all locations, and linepack was recovered in the Northern Zone.

Compressors, regulators, and city-gates were adjusted at the beginning of the simulation to keep the LA Basin above MINOP. However, the linepack did not recover in the Southern Zone.

# III. 1-in-10 Simulation 5 Sensitivity Modeling

## Introduction

This section presents the results of the sensitivity analysis focusing on how much natural gas inventory at the Aliso Canyon storage facility is needed to ensure winter reliability in 2030. This work is part of research conducted to comply with Senate Bill 380 (SB380), which requires the Commission to investigate the feasibility of minimizing or eliminating the use of Aliso Canyon natural gas underground storage facility. The sensitivity analysis in this report builds off Simulation 5, the 2030 Winter Peak (1-in-10) simulation, discussed in Section II "Report on 1-in-10 Scenarios Modeling Results for SB380." The analysis in the 1-in-10 scenarios report was presented at a CPUC workshop in July, and the sensitivities results is this section were presented at a CPUC workshop in October. The Simulation 5 sensitivities are intended to answer the following questions:

1) With reduced inventory levels at the non-Aliso gas storage fields, what withdrawal rate would be needed from Aliso Canyon to ensure 1-in-10 cold winter day reliability?
2) What would be the minimum required Aliso Canyon inventory levels as non-Aliso inventory levels decrease?

## Simulation 5 Overview

The CPUC conducted hydraulic modeling of six scenarios, as presented in Section II of this report, "1-in-10 Scenarios Modeling." For the Aliso inventory sensitivities, the CPUC focused on Simulation 5, which used inputs for winter 2030. Simulation 5 is the only 1-in-10 reliability simulation conducted in the Phase 2 Aliso Canyon modeling that allowed the usage of Aliso Canyon withdrawals.

Simulation 5 assumed that pipeline receipts were somewhat higher than 2019 actuals, and assumed that the non-Aliso storage facility inventories were at 90 percent of maximum capacity. It determined that even under these conditions, an Aliso withdrawal rate of 520 MMcfd would be needed to meet a 1-in-10 cold day winter demand. Simulation 5 was originally conducted by SoCalGas. The CPUC replicated Simulation 5 and arrived at a similar conclusion: the required withdrawal rate from Aliso Canyon would need to be 525 MMcfd to restore the linepack, which is the amount of gas present in the pipeline system.

Although the base case Simulation 5 was considered to have failed marginally due to violations of minimum operating pressures in the San Joaquin Valley, as described in Section II, "1-in-10 Scenarios Modeling" this simulation is instructive in determining the flows needed from Aliso Canyon if other non-Aliso storage fields are at 90 percent inventory levels. SoCalGas will further investigate the San Joaquin Valley and determine whether a system improvement is required.

Southern California Gas Company is required to plan for the CPUC-mandated 1-in-10 reliability standard. This standard requires that the gas system be planned to meet all gas demand from every customer, including core; noncore, non-electric generation; and noncore, electric generation customers, on the coldest day in a 10-year period. The reliability standards were established in D.02-11-073 and D.06-09-039.

## Sensitivities Overview

ED staff conducted sensitivity analyses using the Synergi Gas software to study Winter 2030 (Simulation 5) with non-Aliso inventory levels of 37, 50, and 70 percent. The goal of these three sensitivities was to determine the withdrawal rates needed from Aliso Canyon if the other fields contained decreasing inventories. Field inventories typically decrease throughout the winter as they are used, and a lower inventory at a given facility means lower pressure, often resulting in a lower maximum withdrawal rate at that facility. The CPUC used the withdrawal rates resulting from hydraulic modeling and withdrawal curves for each storage field that were provided by SoCalGas. For each sensitivity, the CPUC modeled the Aliso Canyon inventory level necessary to meet demand.

The three non-Aliso inventory levels used in the sensitivities were selected based on historical actuals. Inventory levels decrease throughout the winter, as gas is withdrawn to meet demand. The non-Aliso natural gas storage fields' inventory levels in February averaged 67 percent from 2017 through 2020. The non-Aliso fields' inventories reached a level of 37 percent in late February 2019.

Simulation 5 and associated sensitivities tested the level of Aliso Canyon withdrawal that would be required on a single 1-in-10 winter day. They do not analyze consecutive cold days or an entire cold year. The Feasibility Assessment in Section V of this report assesses gas inventory needs in the event of multiple cold days in a season.

## Results Overview

The simulation 5 base case showed that Aliso Canyon withdrawals were required even when the non-Aliso fields were 90 percent full. At lower non-Aliso inventories, greater Aliso withdrawals are needed, as shown by the sensitivities.

## Overview of Demands, Supplies, Methodology

### Demands

The following table states the gas demand from each customer class and the information source used for Simulation 5, referred to as the base case, and the sensitivities in this section.

Table III- 1 Gas Demand Categories for Simulation 05

| Customer Class | S05 Winter 2030 Demand (MMcfd) | Source |
|---|---|---|
| Core | 3,034.0 | SoCalGas forecast for 2030 1-in-10 peak design day |

| | | |
|---|---|---|
| Noncore, Non-Electric Generation, | 664.6 | SoCalGas forecast for 2030 1-in-10 peak design day |
| Noncore, EG | 1,122.6 | Calculated by the CPUC Energy division using the SERVM Production Cost Modeling and forecasts from the recently adopted Reference System Plan (RSP) in the Integrated Resource Planning (IRP) Proceeding. |
| **Total Demand** | **4,821.2** | |

The following table compares the CPUC-generated gas demands to the SoCalGas forecast for 2030.

Table III- 2 Comparison of CPUC Forecasted Gas Demands to SoCalGas 2030 Forecasted Gas Demands

| Demand Source | S05 Winter 2030 Demand (MMcfd) | Comment |
|---|---|---|
| SoCalGas Forecast Demand | 4,519 | |
| CPUC Forecasted Demand | 4,822 | CPUC EG demand forecast is higher than SoCalGas EG demand forecast |
| Difference | +303 | |

## Supplies

Simulation 5 assumed 85 percent receipt point utilization (RPU) of nominal capacities for the Northern and Southern Zones, and 100 percent for the Wheeler Ridge Zone. The nominal capacities are 1,590 MMcfd in the Northern Zone, 1,210 MMcfd in the Southern Zone, and 765 MMcfd in the Wheeler Ridge Zone, totaling 3,565 MMcfd (nominal). The total receipt capacity is 3,115 after decreasing the Northern and Southern Zones by 15 percent. For planned outages, the modeling simulations assumed Line 3000, Line 235-2 and Line 4000 were operating at reduced pressures but not entirely out of service.

The Table III-3 below details the pipeline receipts and maximum storage withdrawals assumed possible under Simulation 5. The Aliso Canyon withdrawal rates resulting from the simulations are lower than the maximum values shown in table below.

Table III- 3 Gas Pipeline Receipt Points and Maximum Withdrawal Rates allowed from Storage Fields for Simulation 5 and Sensitivities

| Receipt Points | S05 Winter 2030 (Base Case) | Sensitivity 1 Non-Aliso 70% Inventory | Sensitivity 2 Non-Aliso 50% Inventory | Sensitivity 3 Non-Aliso 37% Inventory |
|---|---|---|---|---|
| Cal Producers | 70 | Same as Base Case | Same as Base Case | Same as Base Case |
| Wheeler Ridge | 765 | Same | Same | Same |
| | | | | |
| Blythe Ehrenberg | 980 | Same | Same | Same |
| Otay Mesa | 50 | Same | Same | Same |
| Total Southern Zone | 1,030 | Same | Same | Same |
| | | | | |
| Kramer Junction | 420 | Same | Same | Same |
| North Needles | 430 | Same | Same | Same |
| South Needles | 400 | Same | Same | Same |
| Total Northern Zone | 1,250 | 1,250 | 1,250 | 1,250 |
| | | | | |
| Total Pipeline Receipts | 3,115 | 3,115 | 3,115 | 3,115 |
| | | | | |
| Storage Max W/D | 2,594 | 2,381 | 2,181 | 2,050 |
| | | | | |
| Total Available Supplies | 5,709 | 5,496 | 5,296 | 5,165 |

The following are the withdrawal rates by field.

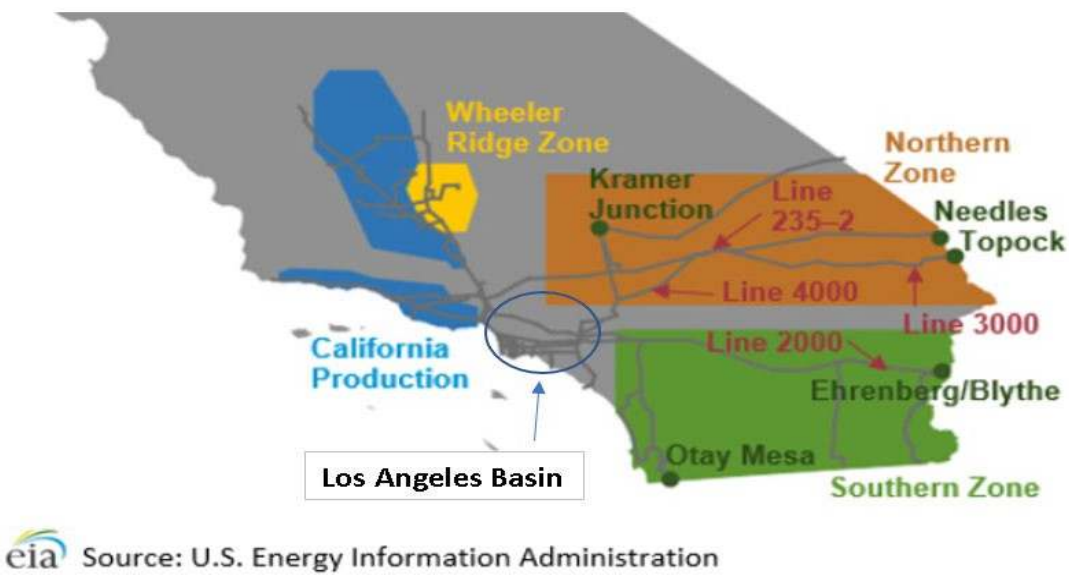
Table III- 4 Maximum Withdrawal Rates allowed from Storage Fields for Simulation 5 and Sensitivities

| Storage Fields | S05 Winter 2030 (Base Case) | Sensitivity 1 Non-Aliso 70% Inventory | Sensitivity 2 Non-Aliso 50% Inventory | Sensitivity 3 Non-Aliso 37% Inventory |
|---|---|---|---|---|
| Honor Rancho Max W/D (withdrawal) | [redacted] | [redacted] | [redacted] | [redacted] |
| La Goleta Max W/D | [redacted] | [redacted] | [redacted] | [redacted] |
| Playa Del Rey Max W/D | [redacted] | [redacted] | [redacted] | [redacted] |
| Non_Aliso Max W/D | 1,329 | 1,116 | 916 | 785 |
| Aliso Max W/D | 1,265 | 1,265 | 1,265 | 1,265 |

## Maps of SoCalGas Pipeline System

To illustrate the gas pipeline receipt points, Figure III-1 is a map of the pipeline system. Natural gas enters the SoCalGas pipeline system at the five receipt points on the borders of the system and flows toward the Los Angeles Basin, circled on the following map. This map shows the Wheeler Ridge Zone receipt point in the northwest. The Kramer Junction, Needles, and Topock Zones are shown in the north and northeast. The Ehrenberg/Blythe and Otay Mesa receipt points are pictured in the southeast and southern portion of the map. Finally, the California production area is shown in the northwest area. Pipelines from each receipt point are connected to the Los Angeles basin, located in the southwest area of the map,

Figure III - 1 Map of Receipt Points




The majority of system demand occurs in the Los Angeles Basin, shown on the following map. The two natural gas storage fields circled below, Aliso Canyon and Playa del Rey, are located in the Los Angeles Basin. The Honor Rancho storage field is just north of the Los Angeles Basin, and the La Goleta storage field is northwest of the Los Angeles Basin.

Figure III - 2 Map of Storage Fields


## Methodology

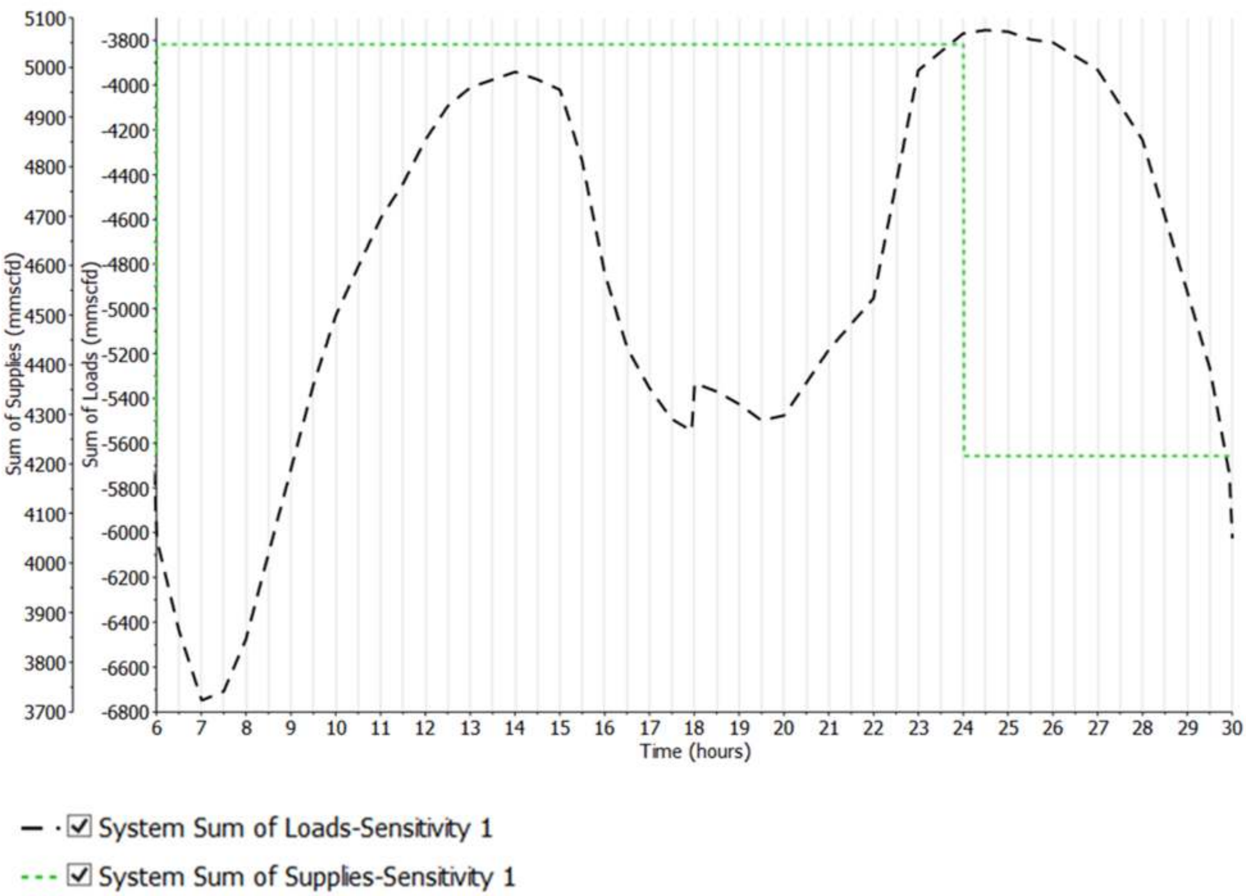
The CPUC used the Synergi Gas model to run the sensitivities on the Simulation 5 base case. The Synergi Gas model takes inputs at the beginning of the day, simulates the gas flowing through the system and the demand changing throughout the day, calculates the linepack using inputs described and static inputs that are characteristics of the infrastructure, such as minimum pressure requirements, provided by SoCalGas. The CPUC adjusted pressures at certain compressors and regulators during the 24-hour period to maintain pressures within limits given the variable demand throughout the simulation. The methods for the sensitivities are the same as for the base case, with variations in the sensitivities for the withdrawal rates from the non-Aliso Canyon fields and changes in operational actions at the compressor and regulators.

## Sensitivity 1 – Non-Aliso Inventory 70%

Sensitivity 1, with non-Aliso inventory levels of 70 percent, resulted in a required Aliso Canyon withdrawal rate of **830 MMcfd.** The plot below depicts the supply from pipeline receipts and storage withdrawals and the demand throughout the 24-hour simulation.

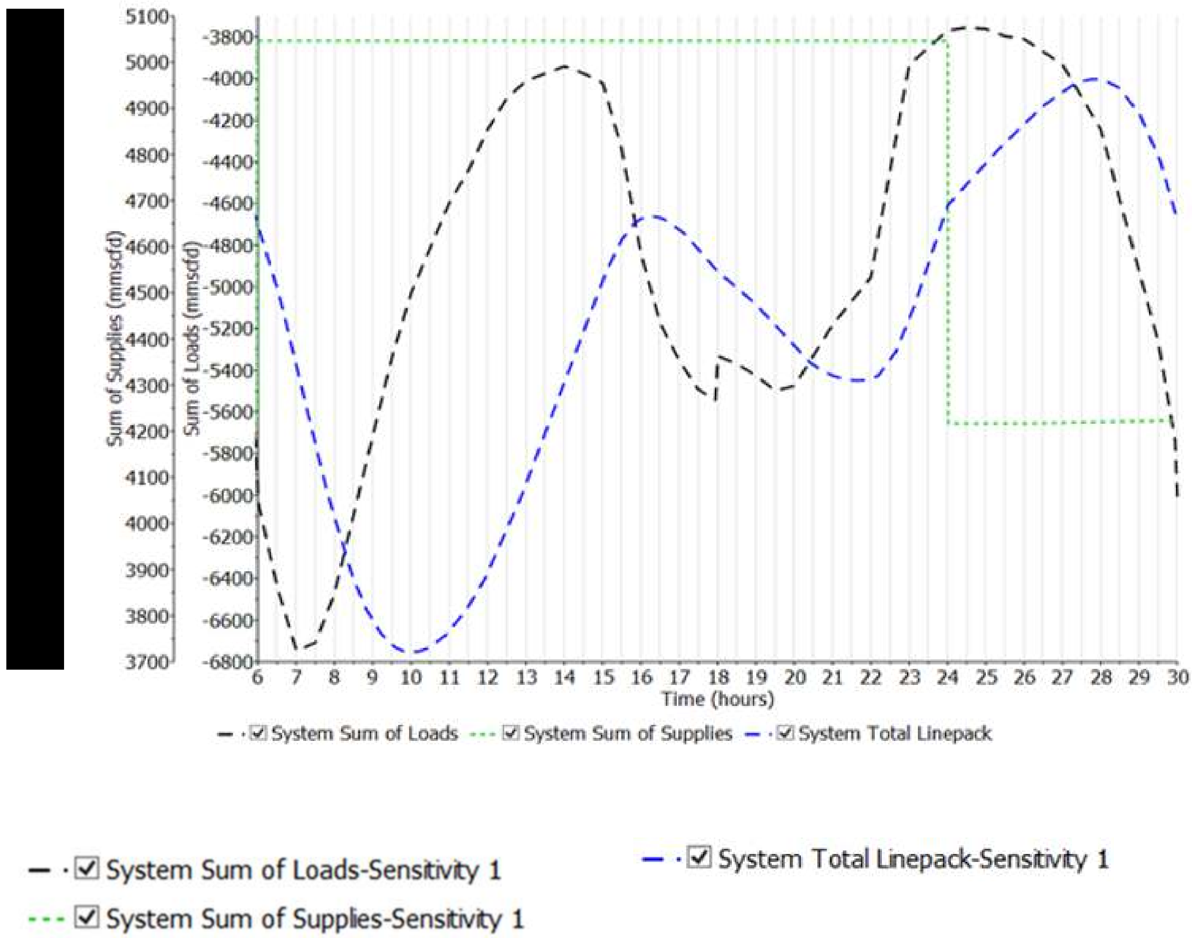
In this sensitivity, the linepack was restored by the end of the simulation, which is an indicator of a successful simulation. Due to confidentiality, the linepack quantity is not presented in the graphic below. Linepack is the amount of gas in the SoCalGas pipeline system at a given time, which can vary within a safe range as pipeline pressure varies. Linepack at the end of the simulated day must equal linepack at the beginning of the day, i.e. linepack must be "recovered" so that it does not continue to decrease over time.

Figure III - 3 Sensitivity 1 – Non-Aliso Inventory 70%: Loads and Supplies




The following plot of supplies and load includes the linepack plot in the blue dashed line. The linepack, shown in the blue dashed line, is approximately equal at time 6 and at time 30: [redacted]

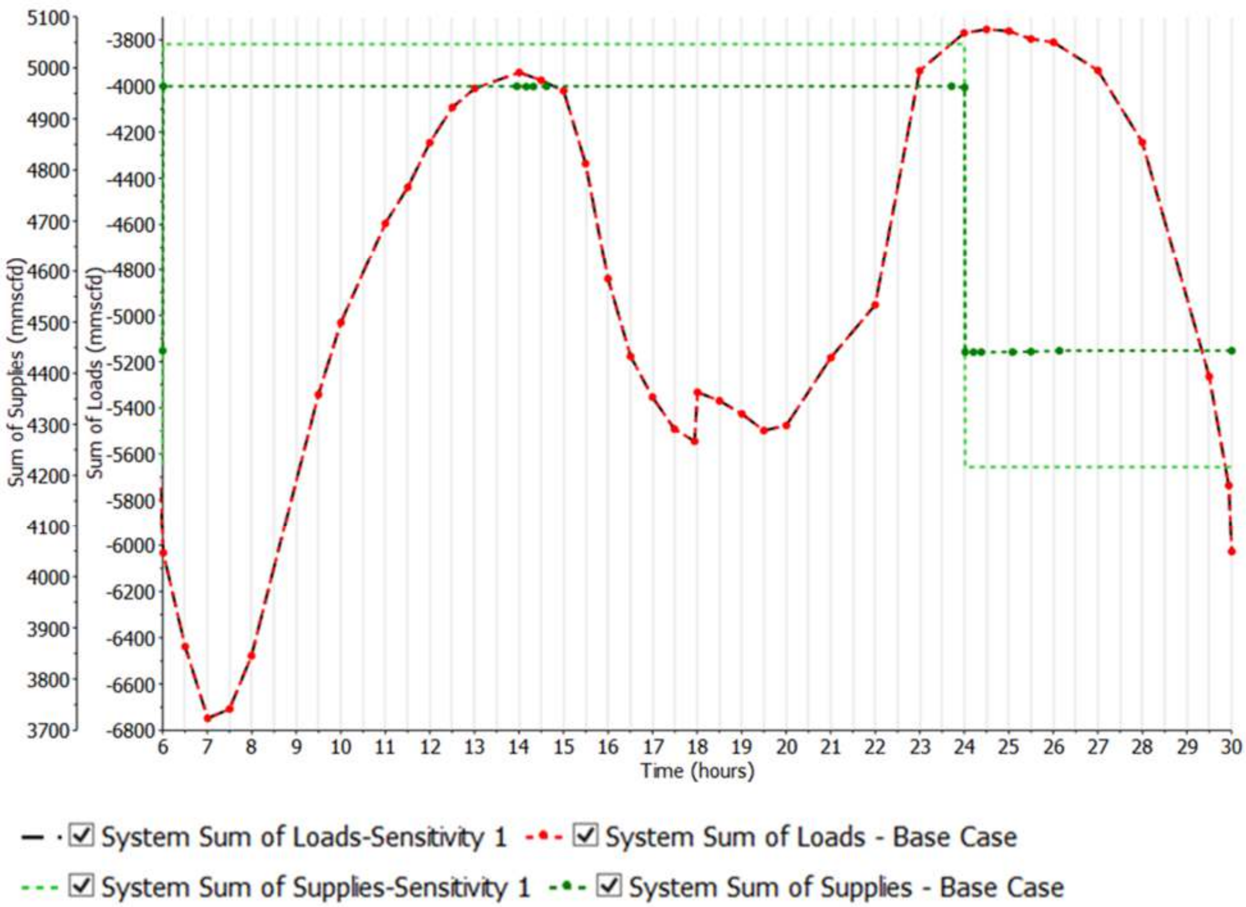
Figure III - 4 Sensitivity 1 – Non-Aliso Inventory 70%: Loads, Supplies and Linepack




The X axis shows 24 hours from 6 am through 6 am the next day, represented by hour 30. Midnight is shown at hour 24. The Y axis includes two sets of data. The loads, shown in the black dashed line, are the customer demand in negative numbers. The morning peak occurs at 7 am, followed by a smaller evening peak at 18:00 or 6:00 p.m. The supply is about 5,050 MMcfd from hour 6 to 24, and 4,250 MMcfd from hour 24 through 30.

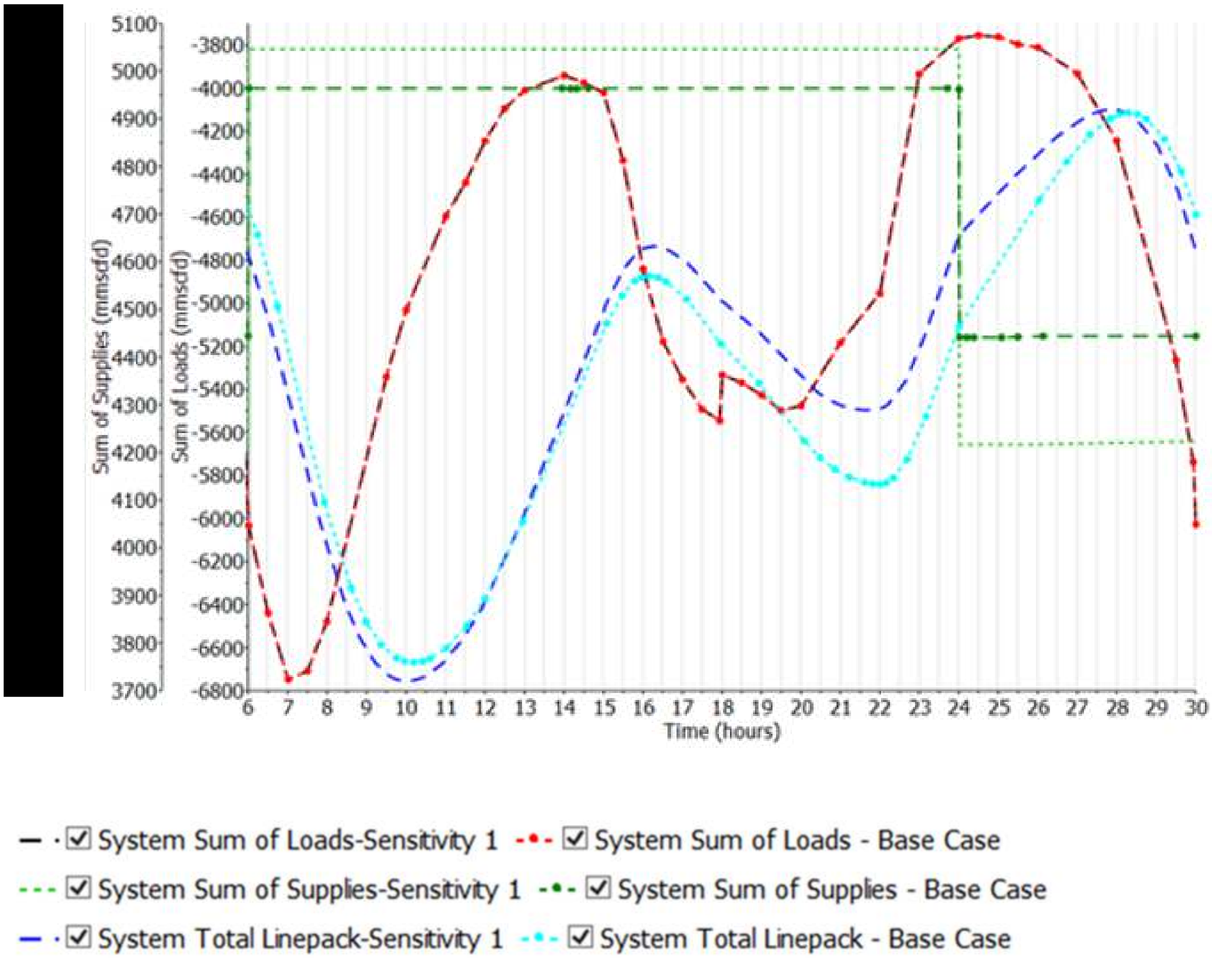
By overlaying the 70 percent sensitivity case shown above with the base case, which has 90 percent non-Aliso inventory level, one can see in the following figure that the demands (black and red lines) are the same. The supplies provided (green lines) vary somewhat more throughout the day in the sensitivity case. The withdrawals from the non-Aliso fields are lower than the base case and last for all 24 hours of the simulation. The withdrawals from Aliso Canyon occur from times 6-24 hour, and they are higher than the base case.

Figure III - 5 Sensitivity 1 – Non-Aliso Inventory 70% Loads and Supplies — Overlayed with Base Case




The following plot includes the loads, supplies, and linepack for sensitivity 1 overlayed with the base case. The linepack in this sensitivity, represented by the dark blue dashed line, is slightly different throughout the day than the base case, represented by the aqua line. The linepack was restored at a slightly different time, since the supplies are different than the base case. At time 6, the linepack was [redacted], and at time 30, it was [redacted]

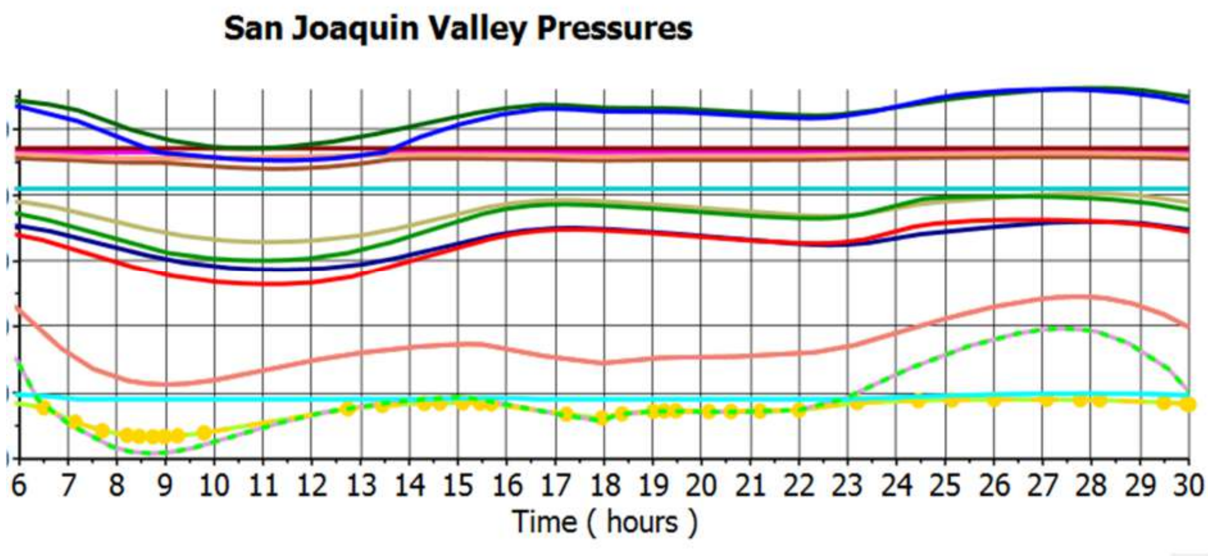
Figure III - 6 Sensitivity 1 – Non-Aliso Inventory 70% Loads, Supplies and Linepack — Overlayed with Base Case




## Sensitivity 1 – Non-Aliso Inventory 70% Minimum Operating Pressure Results

As in the base case, the pressures dropped below the minimum operating pressures for certain nodes in the San Joaquin Valley. However, the pressures rose above their minimum operating pressures, ending the violations, before the end of the simulation. The specific pressures shown on the X axis and the node names represented by the colored lines are confidential.

Figure III - 7 Sensitivity 1 – Non-Aliso Inventory 70%, San Joaquin Valley Pressures




## Sensitivity 1 Summary of Results

The following table shows how this sensitivity performed with respect to each criterion for success. Although some violations of minimum and maximum operating pressures occurred, all but one returned to allowable levels during the simulation. The sensitivity is instructive in showing the required Aliso withdrawal rates given the simulation input.

Table III- 5 Sensitivity 1 – Non-Aliso Inventory 70% — Criteria for Success or Failure

| | Criteria for Success of Simulation | Criteria Met? | Notes |
|---|---|---|---|
| 1 | Pressures above Minimum Operating Pressures (MinOP)? | Yes (a) | 9 exceptions in San Joaquin Valley, all returned from violations during simulation |
| 2 | Pressures below Maximum Operating Pressures (MOP)? | Yes (a) | Two nodes exceeded max pressures by minor amounts; one returned from violation during simulation, and one did not return from minor violation |
| 3 | Linepack recovered? | Yes | |
| 4 | Facilities operated within capacities? | Yes | Storage field pressures at time 30 are within 1% of pressures at time 6 |
| (a) Although some pressure violations occurred, the simulation was instructive of the Aliso Canyon withdrawal rate for the simulation. | | | |

Additionally, demand was met, with supply of 5,061 Bcf exceeding demand of 4,821 Bcf.

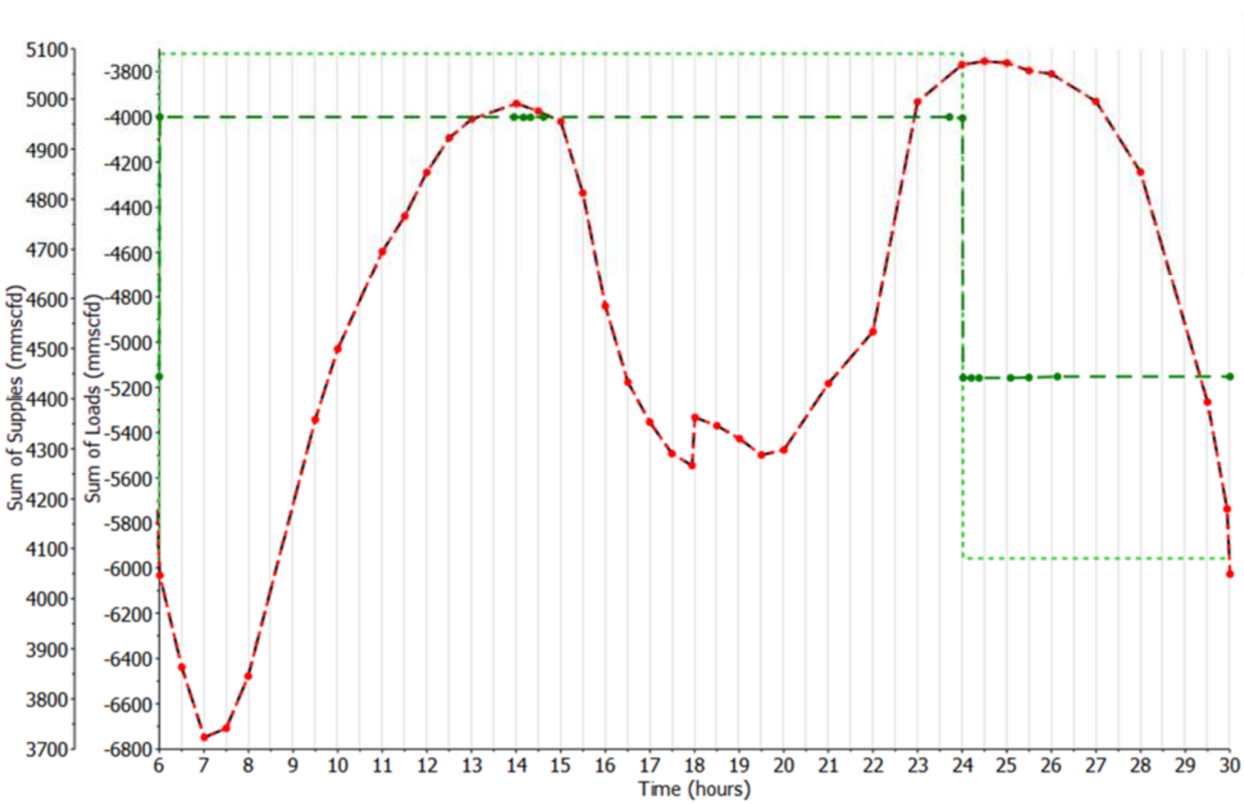
## Sensitivity 2 – Non-Aliso Inventory 50%

Sensitivity 2, with non-Aliso inventory levels of 50 percent, resulted in an Aliso Canyon withdrawal rate of **1,010 MMcfd.** The below plot depicts the supply from pipeline receipts and storage withdrawals and the demand throughout the 24-hour simulation.

In this sensitivity, the linepack was restored by the end of the simulation, which is an indicator of a successful simulation. The linepack is not shown on the following plot for confidentiality reasons

By overlaying the 50 percent sensitivity case shown above with the base case, which has 90 percent non-Aliso inventory level, one can see in the following figure that the demands (black and red lines) are the same. The supplies provided (green lines) vary somewhat more throughout the day in the sensitivity case. The withdrawals from the non-Aliso fields are lower than the base case and last for all 24 hours of the simulation. The withdrawals from Aliso Canyon occur from times 6-24 hour, and they are higher than the base case.

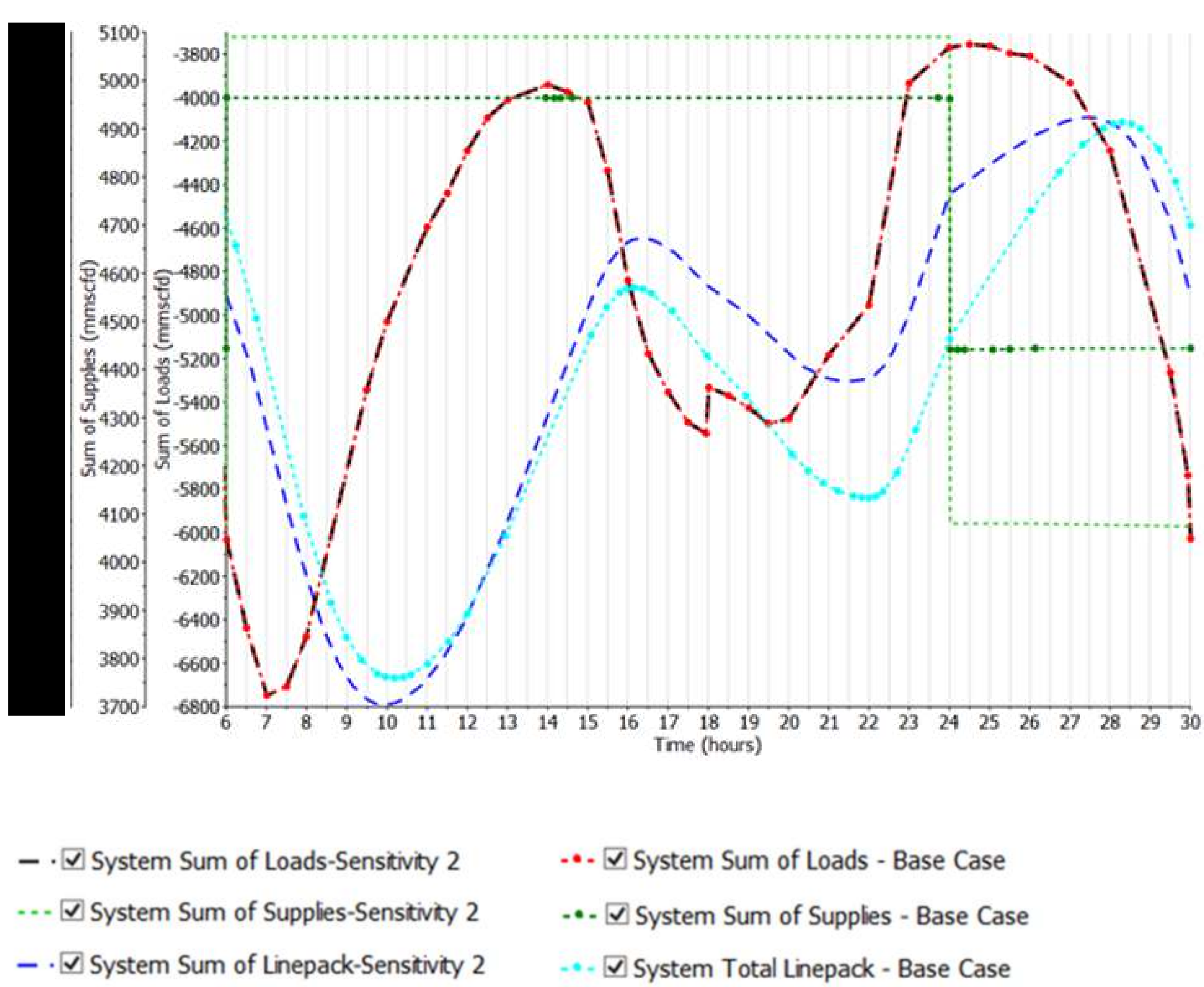
Figure III - 8 Sensitivity 2 – Non-Aliso Inventory 50% Loads and Supplies - Overlayed with Base Case



— · ☑ System Sum of Loads-Sensitivity 2
-•- ☑ System Sum of Loads - Base Case
--- ☑ System Sum of Supplies-Sensitivity 2
-•- ☑ System Sum of Supplies - Base Case

The following plot of loads, supplies, and confidential linepack for sensitivity 2. The linepack in this sensitivity, represented by the dark blue dashed line, is slightly different throughout the day than the base case, represented by the aqua line. The linepack was restored at a slightly different time, since the supplies are different than the base case. At time 6, the linepack was [redacted], and at time 30, it was [redacted].

Figure III - 9 Sensitivity 2 – Non-Aliso Inventory 50% Loads, Supplies, and Line pack - Overlayed with Base Case



## Sensitivity 2 – Non-Aliso Inventory 50% Minimum Operating Pressure Results

As in the base case and sensitivity 1, the pressures dropped below the minimum operating pressures for certain nodes in the San Joaquin Valley. The pressures rose above their minimum operating pressures, ending the violations, before the end of the simulation.

## Sensitivity 2 Summary of Results

The following table summarizes the criteria for success or failure of this sensitivity. Although some violations of minimum and maximum operating pressures occurred, all but one returned to allowable levels during the simulation, and the sensitivity is instructive in showing the required Aliso withdrawal rates given the simulation input.

Figure III - 10 Sensitivity 2 – Non-Aliso Inventory 50% - Criteria for Success or Failure

| | Criteria for Success of Simulation | Criteria Met? | Notes |
|---|---|---|---|
| 1 | Pressures above Minimum Operating Pressures (MinOP)? | Yes (a) | 9 exceptions in San Joaquin Valley, all returned from violations during simulation |
| 2 | Pressures below Maximum Operating Pressures (MOP)? | Yes (a) | Two nodes exceeded max pressures by minor amounts; one returned from violation during simulation, and one did not return from minor violation |
| 3 | Linepack recovered? | Yes | |
| 4 | Facilities operated within capacities? | Yes | Storage field pressures at time 30 are within 1% of pressures at time 6 |
| (a) Although some pressure violations occurred, the simulation was instructive of the Aliso Canyon withdrawal rate for the simulation. | | | |

As in the base case, demand was met, with supply of 5,061 Bcf exceeding demand of 4,821 Bcf.

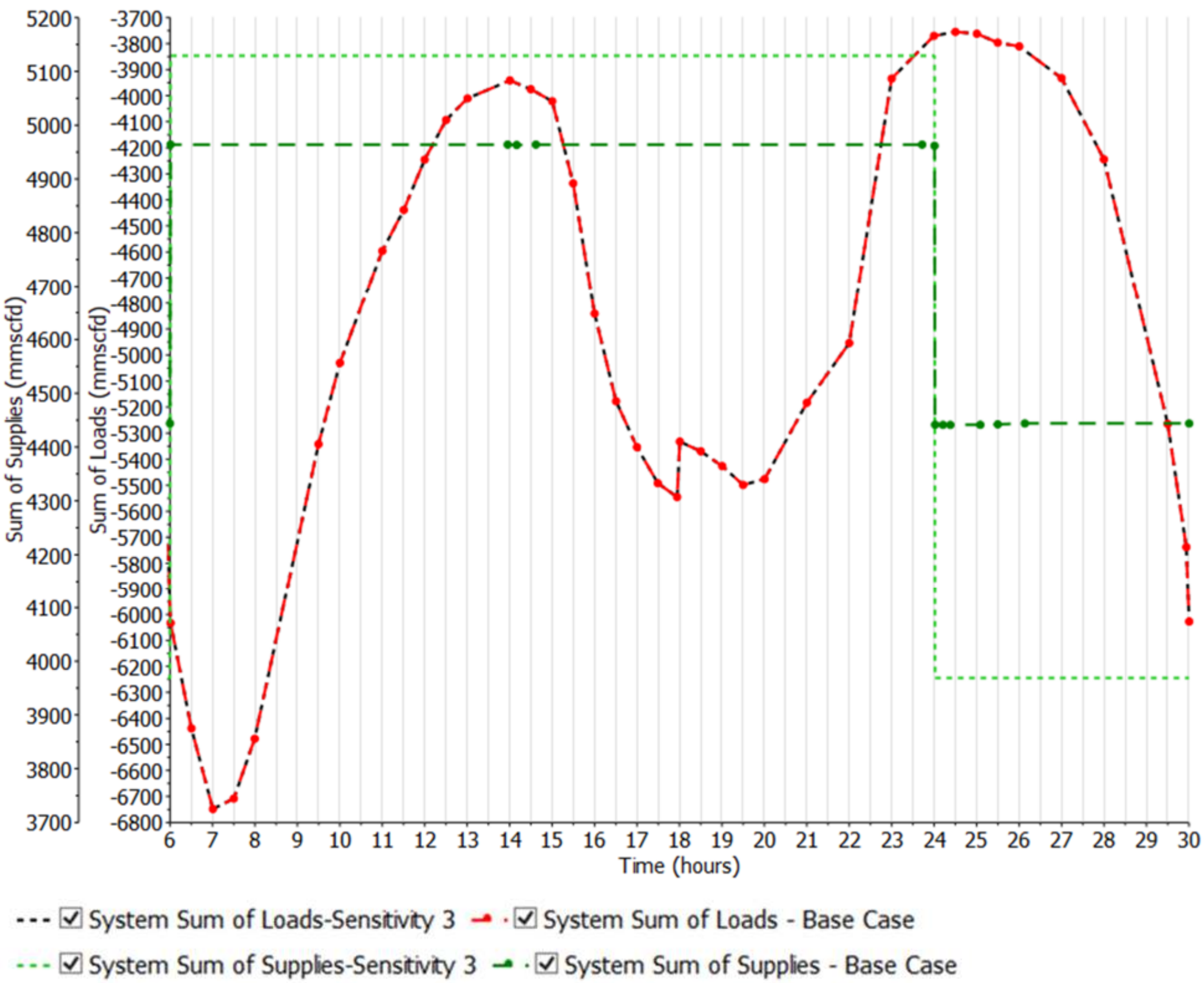
## Sensitivity 3 – Non-Aliso Inventory 37%

Sensitivity 3, with non-Aliso inventory levels of 37 percent, resulted in an Aliso Canyon withdrawal rate of **1,160 MMcfd.** The plot below depicts the supply from pipeline receipts and storage withdrawals and the demand throughout the 24-hour simulation.

As in sensitivities 1 and 2, the linepack was restored by the end of the simulation, which is an indicator of a successful simulation.

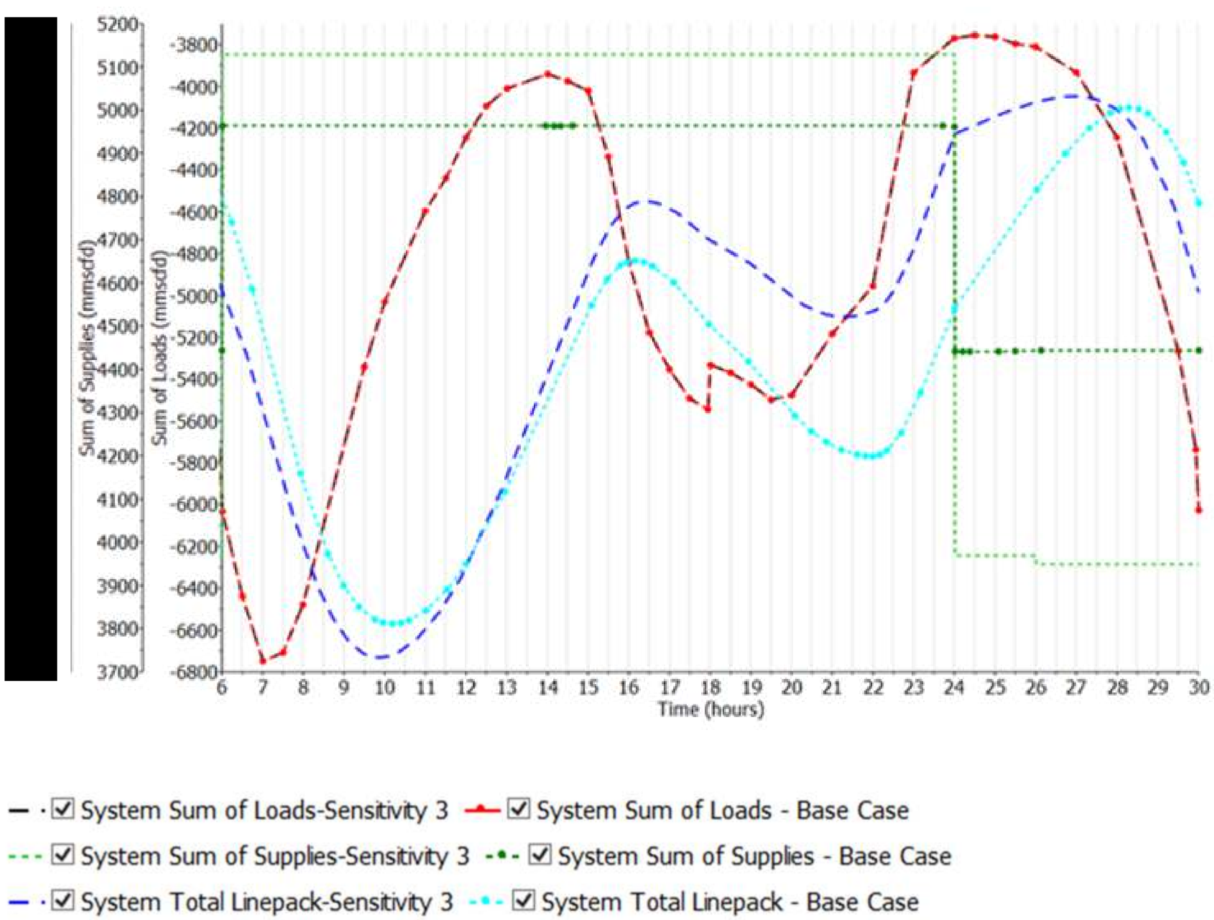
By overlaying the 37 percent sensitivity case shown above with the base case, which has 90 percent non-Aliso inventory level, one can see in the following figure that the demands (black and red lines) are the same. The supplies provided (green lines) vary somewhat more throughout the day in the sensitivity case. The withdrawals from the non-Aliso fields are lower than the base case and last for all 24 hours of the simulation. The withdrawals from Aliso Canyon occur from times 6-24 hour, and they are higher than the base case.

Figure III - 11 Sensitivity 3 – Non-Aliso Inventory 37% Loads and Supplies - Overlayed with Base Case




The following plot of loads, supplies, and confidential linepack for sensitivity 3 . The linepack in this sensitivity, represented by the dark blue dashed line, is slightly different throughout the day than the base case, represented by the aqua line. The linepack was restored at a slightly different time, since the supplies are different than the base case. At time 6, the linepack was [redacted], and at time 30, it was [redacted].

Figure III - 12 Sensitivity 3 – Non-Aliso Inventory 37% Loads, Supplies, Linepack - Overlayed with Base Case




## Sensitivity 3 – Non-Aliso Inventory 37% Minimum Operating Pressure Results

As in the base case and sensitivities 1 and 2, the pressures dropped below the minimum operating pressures for certain nodes in the San Joaquin Valley. The pressures rose above their minimum operating pressures, ending the violations, before the end of the simulation.

## Sensitivity 3 Summary of Results

The following table summarizes the criteria for success or failure of this sensitivity. Although some violations of minimum and maximum operating pressures occurred, all but one returned to allowable levels during the simulation, and the sensitivity indicates the Aliso withdrawal rates required given the simulation input.

Figure III - 13 Sensitivity 3 – Non-Aliso Inventory 37% - Criteria for Success or Failure

| | Criteria for Success of Simulation | Criteria Met? | Notes |
|---|---|---|---|
| 1 | Pressures above Minimum Operating Pressures (MinOP)? | Yes (a) | 9 exceptions in San Joaquin Valley and one additional exception, all returned from violations during simulation |
| 2 | Pressures below Maximum Operating Pressures (MOP)? | Yes (a) | Four nodes exceeded max pressures by minor amounts; three returned from violations during simulation, and one did not return from minor violation |
| 3 | Linepack recovered? | Yes | |
| 4 | Facilities operated within capacities? | Yes | Storage field pressures at time 30 are within 1% of pressures at time 6 |
| (a) Although some pressure violations occurred, the simulation was instructive of the Aliso Canyon withdrawal rate for the simulation. | | | |

As in the base case, demand was met, with supply of 5,061 Bcf exceeding demand of 4,821 Bcf.

## Conclusions on Simulation 5 Sensitivities

The sensitivity analyses resulted in Aliso Canyon withdrawal rates at non-Aliso inventory levels of 70%, 50%, and 37%. The Aliso Canyon withdrawal rates and inventory levels are not listed due to confidentiality. The base case showed that Aliso Canyon withdrawals were required even when the non-Aliso fields were 90 percent full. At lower non-Aliso inventories, greater Aliso withdrawals would be needed, as determined by the sensitivities. The above sensitivities indicate withdrawal capacity to handle a single extreme day. To determine the recommended Aliso Canyon inventory level over an entire season, including one single extreme day, the Feasibility Assessment in Section V analyzes demand over an entire winter season.

The following table shows the Aliso Canyon withdrawal rates and inventory levels for each sensitivity.

Table III 9 Aliso Canyon Withdrawal Rates and Inventory Levels from Sensitivities

| **Sensitivity** | **Non-Aliso Inventory** | **Aliso Canyon Maximum Withdrawal Rate (MMcfd)** | **Aliso Canyon Inventory (Bcf)** |
|---|---|---|---|
| 1 | 70% | 830 | 13 |
| 2 | 50% | 1,010 | 20 |
| 3 | 37% | 1,160 | 27 |

# IV. 1-in-35 Scenarios Modeling

## Scenarios 7 through 9: Overview of Demands, Supplies, Methodology

### Core Demand

SoCalGas and SDG&E plan and design their systems to provide continuous service to their **core** customers under an extreme peak day event. When modeling whether supply is sufficient for the extreme peak day, service to all **noncore** customers is assumed to be fully interrupted (*i.e.*, no service is provided to noncore customers). The "extreme peak day" is defined as a 1-in-35-year-likelihood event for each utility's service area. This extreme peak day is represented by a system average temperature of 40.3 degrees Fahrenheit for SoCalGas' service area and 42.8 degrees Fahrenheit for SDG&E's service area. The following table provides forecasted core demand on an extreme peak day.[26]

Table IV- 1 Core Demand

**Core Extreme Peak Day Demand (MMcf/Day)**

| Year | SoCalGas Core Demand 1/ | SDG&E Core Demand 2/ | Other Core Demand 3/ | Total Demand |
|---|---|---|---|---|
| 2018 | 3,003 | 407 | 117 | 3,527 |
| 2019 | 2,987 | 406 | 118 | 3,511 |
| 2020 | 2,966 | 405 | 119 | 3,490 |
| 2021 | 2,945 | 403 | 120 | 3,468 |
| 2022 | 2,916 | 398 | 120 | 3,435 |
| 2023 | 2,870 | 396 | 121 | 3,388 |
| 2024 | 2,833 | 395 | 122 | 3,350 |

Notes:
(1) 1-in-35 peak temperature cold day SoCalGas core sales and transportation.
(2) 1-in-35 peak temperature cold day SDG&E core sales and transportation.
(3) 1-in-35 peak temperature cold day core demand of Southwest Gas Corporation, City of Long Beach and City of Vernon.

### Electric Generation Demand under a Minimum Local Generation Scenario

Curtailing all noncore customers, as allowed when modeling supply needs for a 1-in-35-year cold event, is an extreme measure impacting all refineries, enhanced oil recovery, a portion of commercial and industrial customers, as well as all Southern California thermal electric generation power plants. Therefore, Energy Division staff decided to investigate the reliability of the natural gas system under a minimum local (electric) generation scenario (MLG), where thermal electric generation in the

[26] California Gas Report, 2018

SoCalGas system is curtailed down to the minimum needed to meet the Local Reliability Criteria according to FERC, rather than full curtailment. All other noncore subclasses are still curtailed. MLG scenarios were run to determine whether the use of Aliso Canyon would be required to meet core demand and maintain local electric reliability during a 1-in-35-year event.

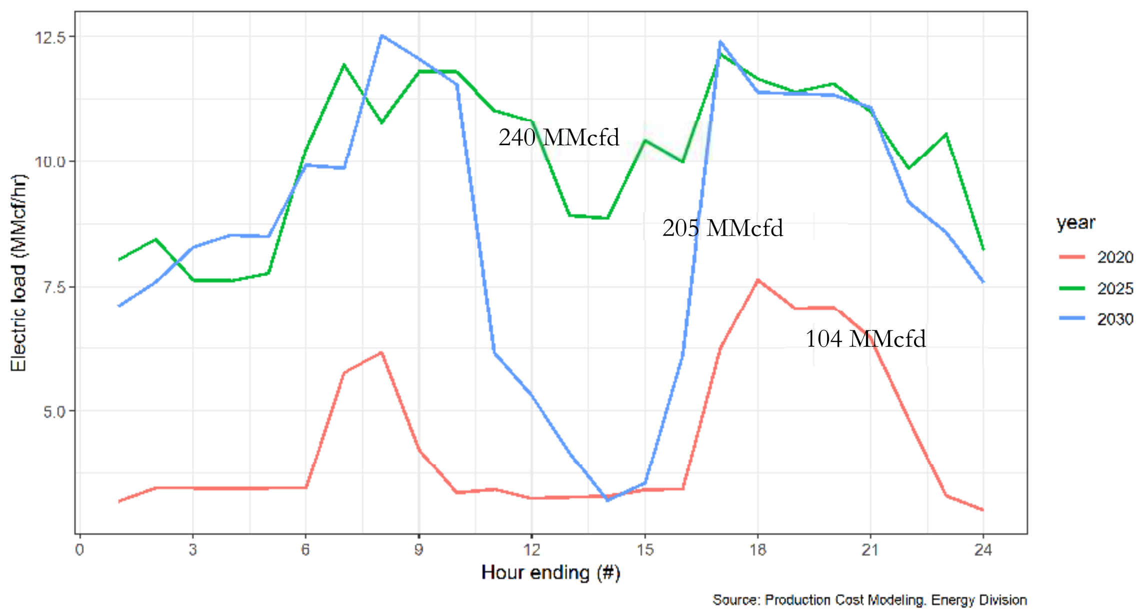
To determine electric generation demand under an MLG scenario, Energy Division staff began with power flow studies of local capacity requirements provided by the California Independent System Operator (CAISO) and the Los Angeles Department of Water and Power (LADWP). Using this data, Energy Division staff executed production cost modeling for three study years (2020, 2025, 2030) and two seasons (winter and summer) using 20 weather years and five load forecast errors. The local capacity requirements were implemented in September and December months as a representative of the summer and winter seasons respectively. Among the 100 possible combinations for each study year and season (month), the month with electric generation gas demand closest to the 97th percentile was selected as representative of a 1-in-35 year with MLG. Within that month, the day of highest gas demand was selected and the hourly fuel burn profiles from that day were extracted for each thermal power plant and imported into the hydraulic model. The gas demand for electric generation during an MLG scenario thus defined is summarized in the following table.

Table IV- 2 Natural Gas Demand during Minimum Local Generation

| | Summer Season (September) | | | Winter Season (December) | | |
|---|---|---|---|---|---|---|
| Study Year | Weather year | Forecast error (%) | Max Demand (MMcfd) | Weather year | Forecast error (%) | Max Demand (MMcfd) |
| **2020** | 2014 | 1.5 | 687 | 2009 | -1.5 | 104 |
| **2025** | 2014 | 1.5 | 736 | 2009 | 1.5 | 240 |
| **2030** | 2014 | 1.5 | 676 | 2009 | 0 | 205 |

Hourly profiles of total natural gas demand for electric generation by year are shown in the next figure. Noteworthy is the steep ramp preceding the evening peak in study year 2030, shown by the blue line.

Figure IV - 1 Hourly Profiles of Natural Gas Demand during Minimum Local Generation in December




Meeting summer demand does not appear to be a challenge under these conditions. The gas demand for electric generation during the summer season under a MLG scenario, is about 33-43 percent lower than that during a 1-in-10 high demand summer day. Further, as noted in [state report section], summer simulations during a 1-in-10 high demand summer day were successful (S02 & S04) or marginally unsuccessful (S06) without the use of Aliso Canyon. Therefore, it is likely that the summer demand during a MLG scenario will be met without the use of Aliso Canyon.

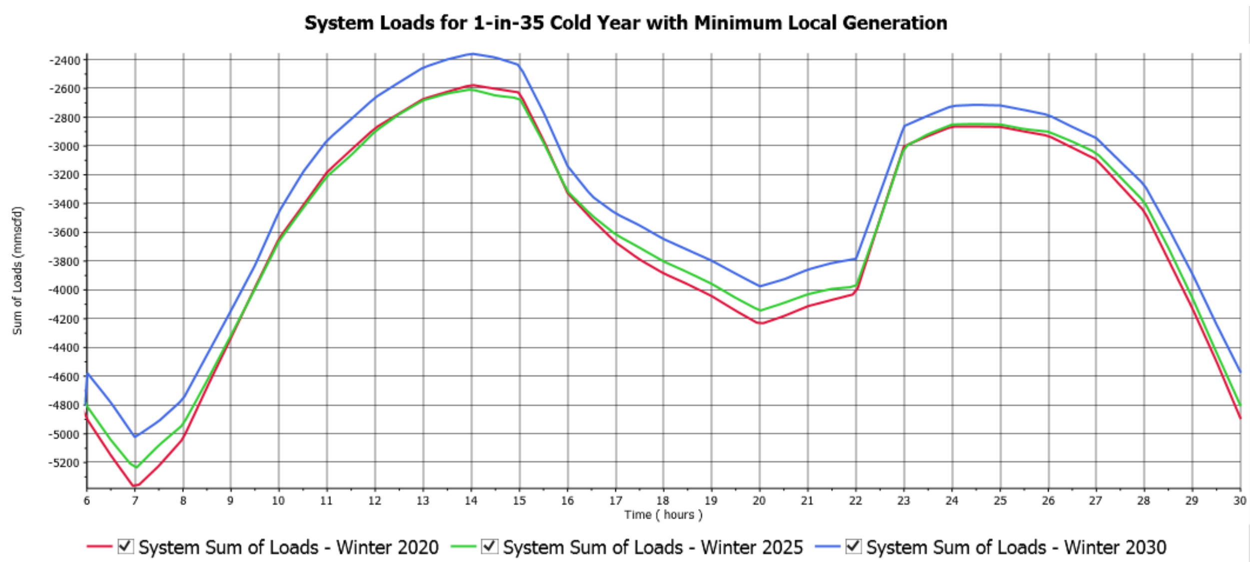
Energy Division staff therefore decided to conduct hydraulic simulations for only the winter season for all three study years. The following table details the gas demand for core, wholesale, and electric generation customers under the MLG scenarios to be modelled.

Table IV- 3 Gas Demands for Scenarios 07-09

| Demands | S07 Winter 2020 (MMcfd) | S08 Winter 2025 (MMcfd) | S09 Winter 2030 (MMcfd) |
|---|---|---|---|
| Core | 3,366 | 3,186 | 3,038 |
| Wholesale | 119 | 123 | 127 |
| EG MLG | 104 | 240 | 205 |
| **Total Demand** | **3,589** | **3,549** | **3,370** |

The hourly profiles shapes used for SoCalGas and SDG&E core customers are the same as those used in Simulations 01 through 06. The hourly profiles used for wholesale customers are uniform (i.e. no hourly variation). When all the loads are combined together (core, wholesale, and EG MLG), the resulting hourly profiles look similar to the 1-in-10 scenarios, but with lower morning and evening peaks. The following figure illustrates the total hourly load of all three MLG scenarios. It is noteworthy that the morning peaks for 2020, 2025, and 2030 are about 5.4, 5.2, and 5 Bcfd[27] respectively, which is almost equal to the daily demand of the 1-in-10 peak day design of study year 2020.

Figure IV - 2 System Loads 2020, 2025, 2030




## Supply

Similar to the 1-in-10 peak design day, the three MLG modeling scenarios in Simulations 07-09 assumed 85 percent receipt point utilization on the Northern and Southern Zones and 100 percent on the Wheeler Ridge Zone, of their nominal capacities (1,590 MMcfd, 1,210 MMcfd, and 765 MMcfd, totaling 3,565 MMcfd), which yields 3,145 MMcfd of available interstate supplies. The three MLG modeling scenarios also made the same unplanned outage assumptions as earlier 1-in-10 simulations, namely that Line 3000, Line 235-2 and Line 4000 were operating at reduced pressures but not entirely out of service, which lowered the available interstate supplies to 3,043.5 MMcfd. No planned outages were assumed.

Underground storage inventory levels were assumed at 90 percent of the maximum inventory and withdrawal capacities were calculated at the corresponding point on each field's maximum withdrawal curve. The following table details the pipeline receipts and maximum storage withdrawals *allowed* for each scenario.

[27] 1Bcfd=1000MMcfd=1000/24MMcfh=41.67MMcfh (million standard cubic feet per hour)

Table IV- 4 Gas Pipeline Receipt Points and Maximum Withdrawal Rates allowed from Storage Fields for Simulations 7 through 9

| Receipt Points | S07 Winter 2020 (MMcfd) | S08 Winter 2025 (MMcfd) | S09 Winter 2030 (MMcfd) |
|---|---|---|---|
| Cal Producers | 70 | 70 | 70 |
| Wheeler Ridge | 765 | 765 | 765 |
| | | | |
| Blythe Ehrenberg | 980 | 980 | 980 |
| Otay Mesa | 50 | 50 | 50 |
| Total Southern Zone | 1,030 | 1,030 | 1,030 |
| | | | |
| Kramer Junction | 420 | 420 | 420 |
| North Needles | 430 | 430 | 430 |
| South Needles | 400 | 400 | 400 |
| Total Northern Zone | 1,250 | 1,250 | 1,250 |
| | | | |
| Total Pipeline Receipts | 3,115 | 3,115 | 3,115 |
| | | | |
| Non-Aliso Max W/D | 1,329 | 1,329 | 1,329 |
| Honor Rancho Max W/D | [redacted] | [redacted] | [redacted] |
| La Goleta Max W/D | [redacted] | [redacted] | [redacted] |
| Playa Del Rey Max W/D | [redacted] | [redacted] | [redacted] |
| Aliso Max W/D | 0 | 0 | 0 |
| Storage Max W/D | 1,329 | 1,329 | 1,329 |
| | | | |
| Total Available Supplies | 4,444 | 4,444 | 4,444 |

The withdrawal rates shown in the table above are the maximum allowed withdrawal rates for each scenario. No withdrawals are allowed from Aliso Canyon for all three MLG scenarios. In all three MLG scenarios, the actual withdrawal rates of the non-Aliso fields were an outcome of the simulation which may be equal to or smaller than the allowed withdrawal rate.

The Capacity Planning Group at SoCalGas conducted the simulations of pipeline flow to assess the ability of the system to supply customers. Each scenario was evaluated by SoCalGas engineers to identify a successful solution and verified by CPUC and LANL analysts. Transient simulations for a 24-hour period were done using the Synergi Gas Unsteady State Module to evaluate the impacts of time-varying loads on the subsystem linepacks and pressures. The criteria for failed or successful simulation remain the same as previously described for Simulations 01-06 in [state section of report].

## Summary of Results

All three scenarios succeeded without the use of Aliso Canyon, owing to the much lower demand compared to the winter demand on a 1-in-10 peak design day. Pressures did not exceed the Maximum Operating Pressures at any location or time. Pressures did not decrease below the Minimum Operating Pressures at any location or time except in the San Joaquin Valley; pressures dropped below MinOP at some nodes in San Joaquin Valley during peak hours due to local limitations rather than a supply deficit. Linepack was recovered, and all facilities operated within their capacities.

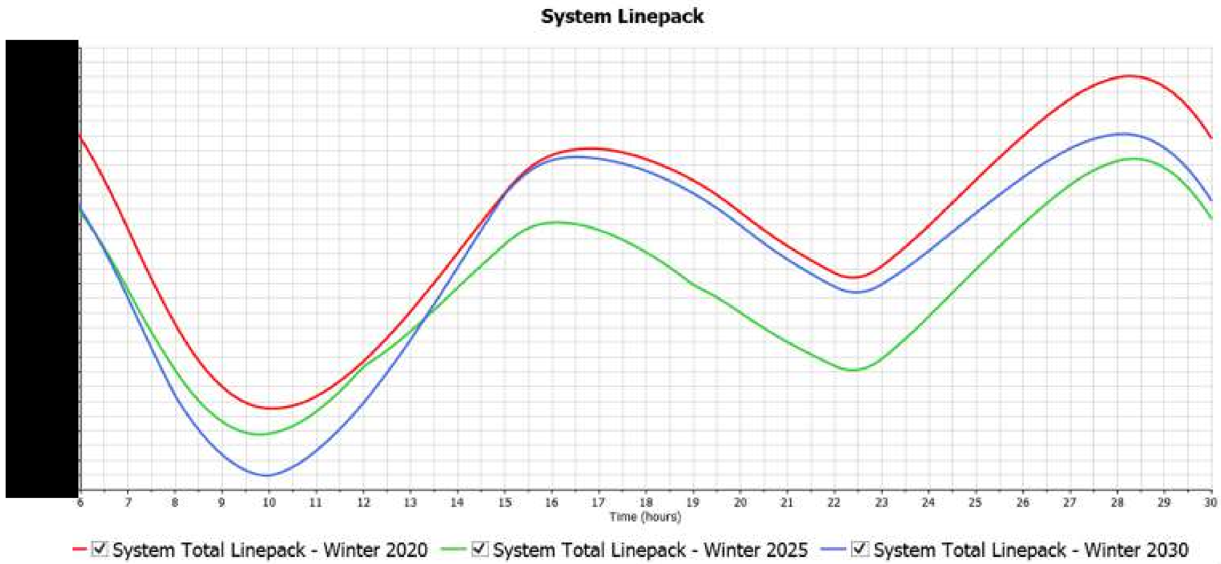
As for storage facilities, neither Honor Rancho nor Playa Del Rey reached their maximum withdrawal rate at any time during these simulations. La Goleta was only near its maximum withdrawal rate in Simulation 08 for a short period of time. It is possible that different operational actions could have led to less use of La Goleta. The table below summarizes the simulation results for the three MLG simulations.

Table IV- 5 Simulation Results S07-S09

| Receipt Points | S07 Winter 2020 (MMcfd) | S08 Winter 2025 (MMcfd) | S09 Winter 2030 (MMcfd) |
|---|---|---|---|
| Demand | **3,589** | **3,549** | **3,370** |
| Pipeline Supply | 3,115 | 3,115 | 3,115 |
| Total Maximum Allowed Withdrawal Rate | 1,329 | 1,329 | 1,329 |
| Total Maximum Actual Withdrawal Rate | ~550 | ~610 | ~470 |
| Total Maximum Allowed Injection Rate | 368 | 368 | 368 |
| Total Maximum Actual Injection Rate | 0 | 0 | 0 |
| Pressures above MinOP | No | No | No |
| Pressures below MOP | Yes | Yes | Yes |
| Linepack Recovered | Yes | Yes | Yes |
| Facilities Operated within Capacities | Yes | Yes | Yes |

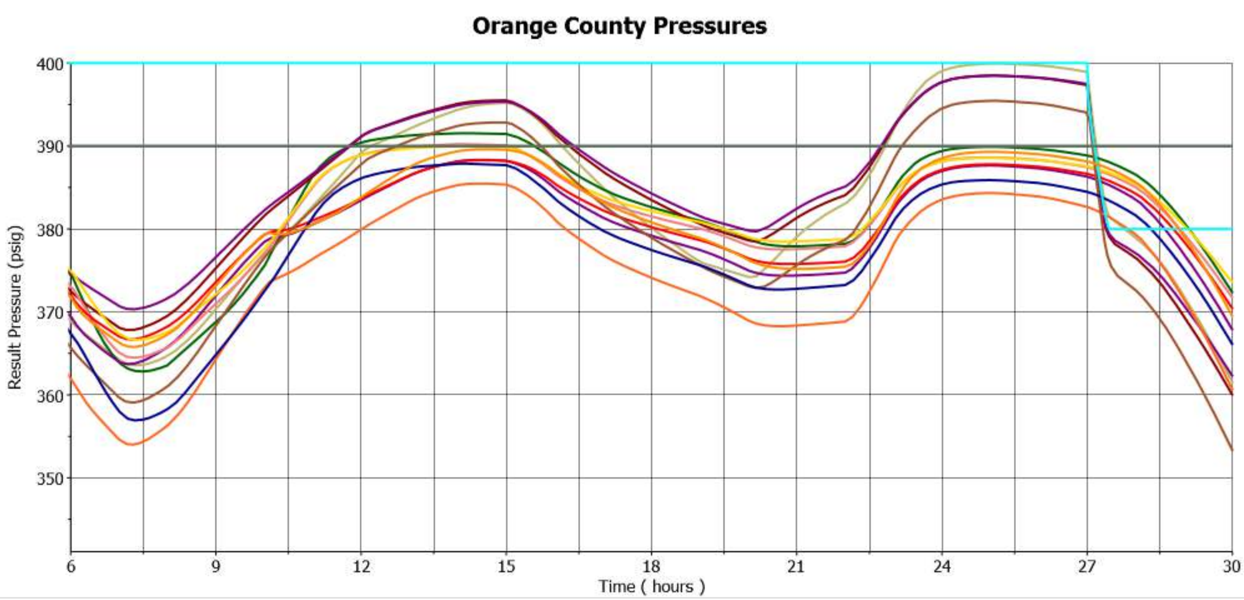
The linepack for all three MLG scenarios is shown in the figure below. For all three MLG scenarios, the linepack was restored at hour 30. In other words, the linepack at hour 30 was equal to or higher than its initial value at hour 6.

Figure IV - 3 System Linepack 2020, 2025, 2030




Pressures were successfully maintained between the Minimum and Maximum Operating Pressures. For example, the pressure at various nodes in Orange Country were maintained well above the Minimum Operating Pressures as shown in the figure below. The only exceptions were pressures below the minimum at nodes within the San Joaquin Valley, which were due to known local limitations rather than a supply deficit.

Figure IV - 4 Time Plot of Pressures



## Conclusions (1-in-35 Modeling)

ED staff note and conclude the following:

1) The daily demand on a 1-in-35 extreme peak day with minimum local generation is about 70%-75% of the daily demand on a 1-in-10 peak day. In other words, the demand level during a 1-in-35 extreme peak day design with minimum local generation is much lower than the demand during a 1-in-10 peak day design due to curtailment of all noncore nonEG customers.
2) The 1-in-35 extreme peak with minimum local generation hydraulic modeling simulations for winter 2020, 2025, and 2030 were successful without the use of Aliso Canyon Underground Storage Field.
3) It follows that the 1-in-35 extreme peak (with noncore curtailments) simulations will also be successful without the use of Aliso.

# V. Feasibility Assessment

## Overview and Objectives

The Scenarios Framework initially assumed that the inventory levels at the non-Aliso fields during a 1-in-10 or 1-in-35 Peak Design Day (PDD) would be near their maximum inventory level. Energy Division Staff's analysis of historical receipt point utilization, however, showed that such an assumption is unrealistic because it does not allow the operator to manage the pipeline and storage system during times when there is excess gas on the system, such as when high operational flow orders (High OFOs) are called. Therefore, ED Staff concluded that the maximum inventory level at the non-Aliso fields should be limited to 90 percent for the 1-in-10 and 1-in-35 analyses.

To analyze the appropriateness of storage inventory levels assumed during peak demand simulations and the ability of those fields to maintain those levels throughout the entire winter season, the Scenario Framework committed ED staff to performing a feasibility assessment of the entire pipeline-storage system during the winter season. ED Staff performed the assessment with the following objectives:

1) Determine if the minimum inventory levels of all storage fields that were assumed in the reliability assessment are achievable (feasible) throughout the winter and summer seasons;[28]
2) Provide more insight to the minimum required inventory level at Aliso Canyon.[29]

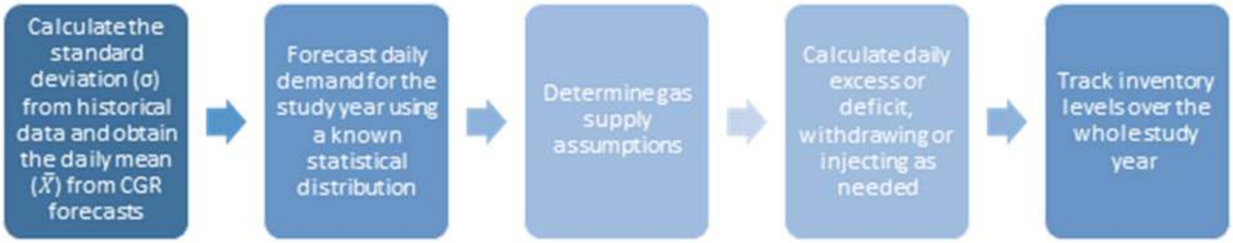
The Scenarios Framework discussed three possible approaches to conduct the feasibility assessment, where the first two use Synergi for steady and transient analyses. However, Synergi proved to be time-consuming because operational actions could not be easily automated and require frequent manual adjustments to stay within the physical constraints of the system (primarily pressure bounds). In addition, the number of simulations required to perform a year-round feasibility assessment is prohibitive. Therefore, the third approach was used, wherein a mass balance was performed to determine inventory levels at the storage fields. In addition, variability inherent in the daily gas demand was introduced by using random draws from known statistical distributions of cold weather days based on historical years.

## Methodology

The model attempts a mass balance on each day of the study year. The model inputs are the forecasted daily demand using random draws from a known distribution, the assumed pipeline capacity, the maximum withdrawal and injection curves, and the working gas capacity of the storage fields. The steps taken to complete the modeling are illustrated in the figure below.

[28] The reliability assessment base cases assumed 90 percent inventory levels in the non-Aliso fields for the winter season and 70 to 90 percent for the summer season.
[29] The reliability assessment provided only a withdrawal capacity required from Aliso Canyon on a 1-in-10 reliability day. However, the reliability assessment did not address or analyze multiple cold days or a cold year

Figure V - 1 Model Steps

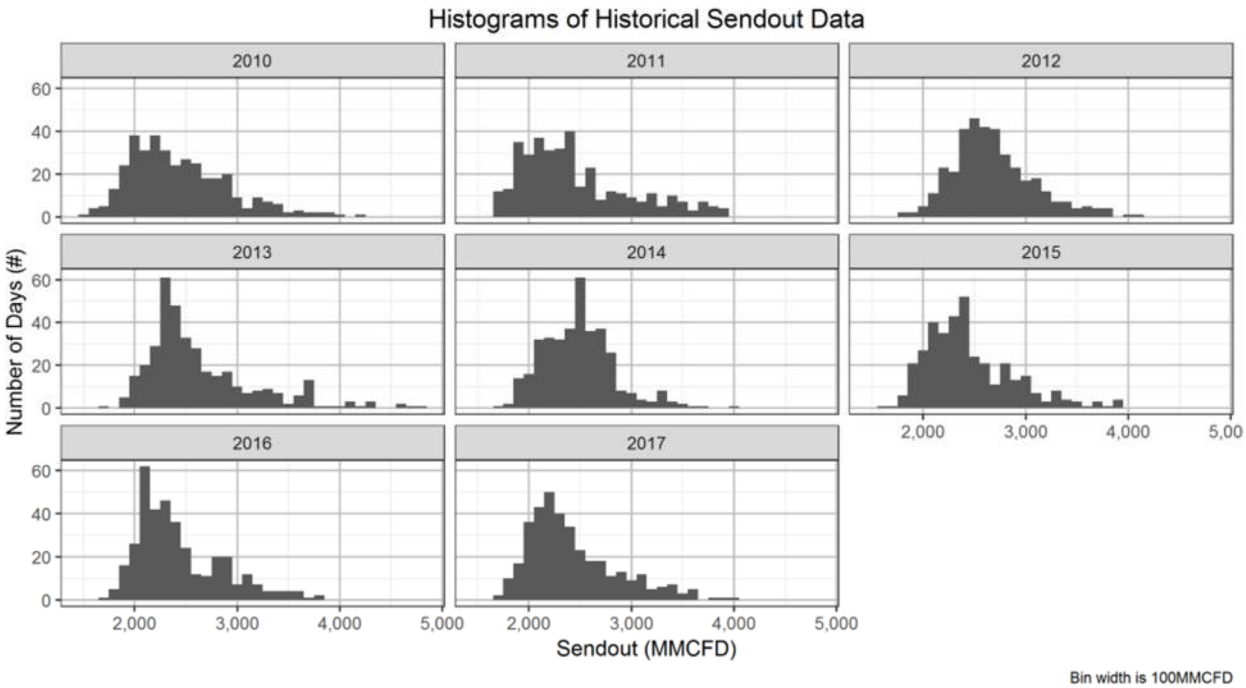



The model determines whether there is an excess or deficit in the gas supply, then injects or withdraws gas accordingly, while adhering to injection and withdrawal limits. If there is not sufficient supply to meet the demand (mass imbalance) on a given day, the model flags that day as an imbalance day or an emergency flow order (EFO) day. EFOs are used as a proxy for an insufficient or excess supply (imbalance). The following sections describe~~s~~ the methodology in more depth along with the assumptions used.

## Analysis of Historical Sendout Data

ED Staff analyzed historical sendout data for the period 2010-2017 using Data Request #6 to understand the underlying distribution of daily gas sendout and to predict or forecast daily sendout for a desired future study year. To that effect, Staff created histograms of sendout by calendar year, which are shown in the figure below.

Figure V - 2 Histograms of Historical Sendout Data




Similarly, ED Staff created histograms of daily natural gas sendout by calendar month. In creating the histograms by calendar month for the period 2010-2017, the daily sendout was normalized by the average sendout of a given month in order to eliminate the observed effects of varying average sendout across the eight calendar years analyzed and to remove artificial skewness due to warming weather caused by climate change.

Both sets of histograms—yearly and monthly—point towards a right-skewed distribution, i.e. with longer tails on the right and other known characteristics (e.g. mode is smaller than the mean). Therefore, a symmetric distribution such as the Gaussian distribution is not appropriate to describe the daily sendout of a given month. Rather, a Gamma distribution is appropriate to use.

Gamma distributions are widely used in engineering to model continuous variables that have skewed distributions, are always positive, and represent an accumulation of events, in this case, many customers each burning gas. Gamma distributions belong to the two-parameter family of continuous probability distributions, and the two parameters can be easily calculated if the mean and the standard deviation are known. The probability density function of a Gamma distribution is:

$$f(x) = \frac{\beta^{\alpha}}{\Gamma(\alpha)} x^{\alpha-1} e^{-\beta x}$$

where $\alpha = \left(\frac{mean}{standard\ deviation}\right)^2$ is the shape parameter,

and $\beta = \frac{standard\ deviation^2}{mean}$ is the inverse scale parameter.

In order to test the validity of the Gamma distribution in predicting the distribution of monthly gas sendout, the normalized daily gas sendout was used to compute the standard deviation for each calendar month in the historical period 2010-2017. The standard deviation and the monthly mean of one were used to compute the Gamma distribution for each calendar month. The resulting Gamma Probability Density Function (PDF) was layered on top of the monthly histograms previously shown. The result is shown in the next figure, where the Gamma PDF is shown in blue dashed curves, while the histograms are "fitted" with a red dashed curve. The Gamma PDF perfectly matches some of the months, such as April, August, and December. For other months, the Gamma PDF underestimates the probability (frequency) of the mode, while overestimating the probability (frequency) of days colder than the mode (in other words, the blue peak is to the right of the red peak). Further validation will be shown later, but based on this replication, ED staff concluded that the Gamma PDF is an appropriate approach to introduce some uncertainty and variability in the feasibility study.

Figure V - 3 Normalized Sendout and Probability

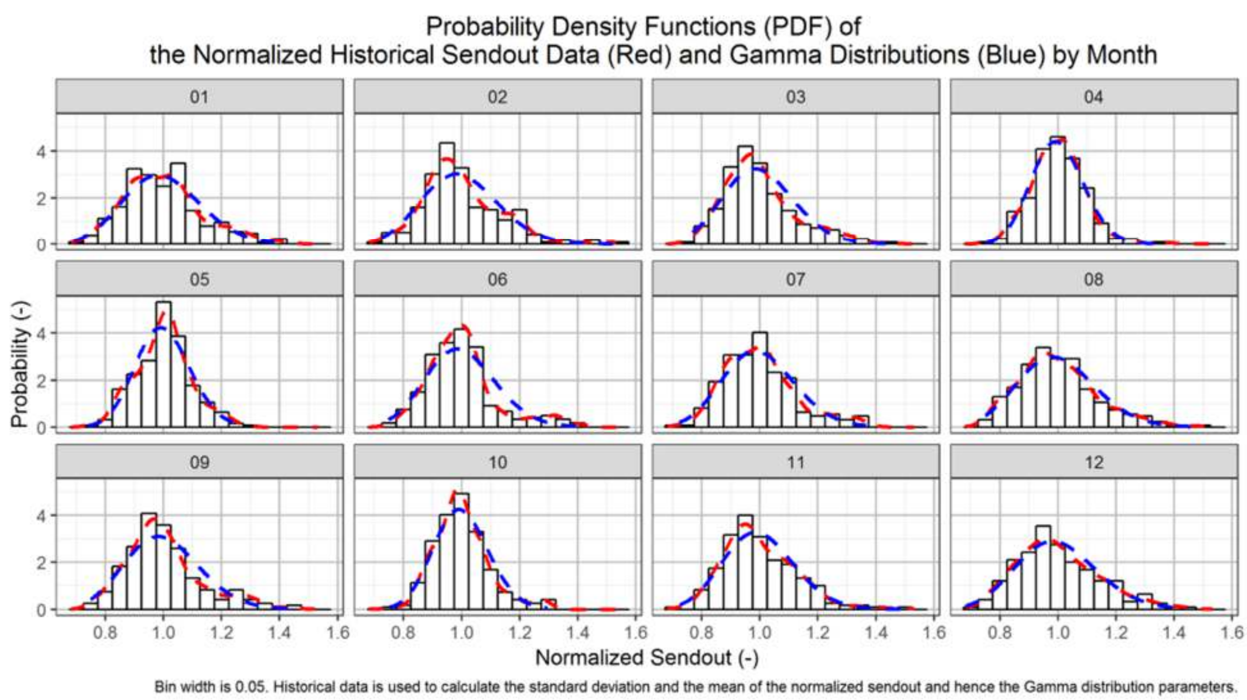


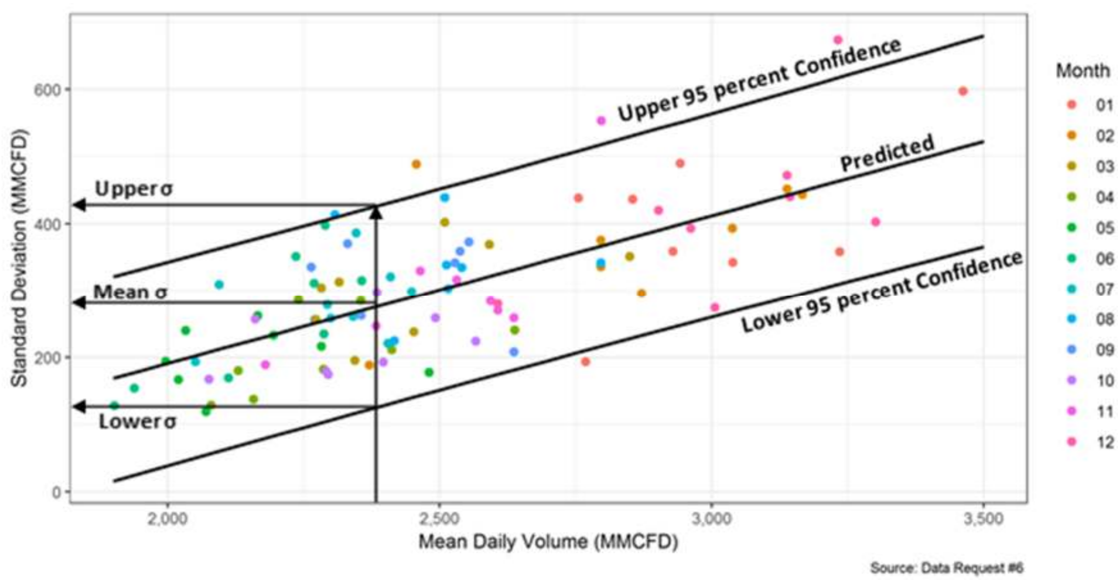
Table V - 1 Forecast of Sendout Data for Study Year 2020

| Month | Average | Cold | Days |
|---|---|---|---|
| | MMCFD | MMCFD | # |
| 1 | 3,080 | 3,376 | 31 |
| 2 | 2,807 | 3,055 | 29 |
| 3 | 2,494 | 2,706 | 31 |
| 4 | 2,433 | 2,618 | 30 |
| 6 | 2,073 | 2,147 | 30 |
| 7 | 2,435 | 2,574 | 31 |
| 8 | 2,623 | 2,785 | 31 |
| 9 | 2,579 | 2,685 | 30 |
| 10 | 2,422 | 2,482 | 31 |
| 11 | 2,595 | 2,778 | 30 |
| 12 | 3,182 | 3,509 | 31 |
| **Mean** | **2,565** | **2,743** | **30.5** |
| **Total** | **939 Bcf** | **1,004 Bcf** | **366** |

Once ED staff determined that a Gamma distribution was appropriate to describe daily gas sendout, it was then used to forecast the gas demand for the feasibility assessment study year, i.e. year 2020. This approach can also be implemented for any future study year. As stated earlier, in order to create the Gamma distribution, the mean and standard deviation for each calendar month must be specified. The monthly mean is found in the 2018 California Gas Report and is summarized in table V-1, for an average year and for a cold year. It is noteworthy that the total natural gas demand forecast for an average 2020 year is 939 Bcf, while that for a cold 2020 year is 1,004 Bcf, a 7 percent increase.

To derive the standard deviation by month, historical data for the 2010-2017 period were used to estimate a correlation between the mean sendout and the standard deviation of the sendout. For each calendar month in this period, ED staff computed the average sendout and the standard deviation of the sendout. The following plot illustrates this correlation, where the x-axis is the mean daily volume or sendout in MMcfd, while the y-axis is the standard deviation in MMcfd. This plot provides a correlation between the mean and the standard deviation of the sendout. The linear correlation is positive (i.e., the standard deviation increases as the mean increases) and weak (correlation coefficient ~0.75) as evident by the scattered data for a given mean, especially when the mean is higher than 2,500 MMcfd. Therefore, for each mean, ED staff selected three values for the standard deviation, one represents the most likely value (i.e. the prediction), while the other two represent the upper and lower 95 percent confidence interval of the most likely value (prediction). ED staff then conducted further analysis to pick the appropriate value of the standard deviation.

Figure V - 4 Standard Deviations and Mean Daily Volumes




To further validate that the Gamma distribution is an appropriate distribution for the daily gas sendout as well as to select the appropriate values of the standard deviation, ED staff performed six dry runs, i.e. a run without actually tracking the storage levels or performing a feasibility assessment. In each dry run, random draws were made from each monthly distribution using the known mean and one of the three selected standard deviation values (predicted and upper and lower 95 percent confidence). For each pair of mean and standard deviation, 10,000 draws were made from each month. This resulted in a yearly distribution that can be analyzed for the number of cold days and compared to previously known years. The dry run was performed for both a cold year and an average year, with each year having three sets of standard deviations (predicted and upper and lower 95 percent confidence), which resulted in six possible yearly distributions (histograms). While the histograms show that the distribution is indeed skewed (and Gamma), the results of the histogram are summarized by the following table for an easier interpretation.

Table V - 2 Expected Number of Days by Demand Range

| | Cold Year | | | Average Year | | |
|---|---|---|---|---|---|---|
| **Demand Range** | **Lower 95** | **Predicted SD** | **Upper 95** | **Lower 95** | **Predicted SD** | **Upper 95** |
| **Bcfd** | **Expected number of days** | | | | | |
| **4.5<Demand** | 0.215 | 1.671 | 4.6 | negligible | 0.172 | 1.23 |
| **4.0< Demand** | 3.83 | 7.497 | 10.97 | 0.19 | 1.86 | 4.77 |
| **3.5< Demand** | 23.27 | 24.93 | 29.58 | 6.33 | 11.67 | 17.78 |
| **0< Demand** | 337.67 | 330.91 | 319.84 | 358.48 | 351.3 | 341 |

In the table above, the demand has been sorted into four bins (lower than 3.5 Bcfd, 3.5-4 Bcfd, 4-4.5 Bcfd, and higher than 4.5 Bcfd). For each bin, the number of days in each bin is shown for each of the six possible distributions ((Cold Year, Average Year) X (Lower 95, Predicted SD, Upper 95)). For example, for an average year and an upper 95 percent confidence interval of the standard deviation, there are 1.23 days with demand higher than 4.5 Bcfd. Similarly, for a cold year and a lower 95 percent confidence of the standard deviation, there are 3.83 days with demand between 4 and 4.5 Bcfd.

The reliability assessment for winter 2020 analyzed a 1-in-10 peak day, where the demand was almost 5 Bcfd. Therefore, it is appropriate for the feasibility assessment to exclude distributions where the demand does not exceed 5 Bcfd for a whole day. This would exclude four out of the six distributions tabulated above and leaves only two possibilities; these are a cold year with an average standard deviation or a cold year with an upper 95 percent confidence standard deviation.

To pick one of these two distributions, ED staff compared the number of cold days to historical data in the period 2010-2017. The coldest year in that period was 2013, which included four days with sendout above 4.5 Bcfd and eight days with sendout in the 4-4.5Bcfd range, totaling 12 days with sendout above 4 Bcfd. Therefore, ED staff concluded that choosing a cold year with an upper 95 percent confidence interval is the more conservative choice as it yields about 15.57 days with demand above 4 Bcfd, while a cold year with an average standard deviation would yield only 9.168 days with demand above 4 Bcfd (compared to 12 days in a recent year: 2013). It is important to note that the choice of the standard deviation does *not* affect the total gas demand used throughout the whole year. In other words, a cold year has a demand of 1,004 Bcf regardless of the choice of the set of the standard deviations. The standard deviation choice affects the distribution (e.g. longer or shorter tails) but *not* the total yearly demand.

Based on this analysis, a cold year with a standard deviation at the 95 percent upper confidence interval (higher end of the confidence interval) was used to conduct the feasibility assessment. This can be thought of as a design criterion of the pipeline-storage system where the system will be designed to support 4.6 days with sendout higher than 4.5Bcfd, 10.97 days with sendout in the 4-4.5 Bcfd range, 29.58 days with sendout in the 3.5-4 Bcfd range, and the remaining 319.84 days with sendout less than 3.5 Bcfd.

## Further Assumptions

In the previous section, the methodology for forecasting the daily gas sendout for the study year 2020 was laid out. However, more assumptions must be made to perform the feasibility assessment, which are described next.

## Interstate Supplies and Scheduled Quantities

Assumptions must be made regarding the availability of interstate supplies. The reliability assessment assumed only unplanned outages, which resulted in interstate supplies of 3,043 MMcfd (which does not include 70 MMcfd of California Production). In the Scenarios Framework, and as pointed out by many stakeholders, the feasibility assessment must take into account both unplanned and planned outages. Therefore, it is reasonable to assume that interstate supplies won't exceed 3,000 MMcfd on average in study year 2020, though the sensitivity of the results to available interstate supplies was investigated. It was also assumed that customers will schedule gas equal to the available interstate supplies.

## Well Availability

As per recent CalGEM regulations, each underground storage field must undergo two shut-ins annually: one in the spring when the inventory is low and one in the fall when the inventory is high. On average, each shut-in lasts about two weeks. In addition, CalGEM's new rules require that each well be inspected every two years, with each inspection lasting two to five weeks.[3] These are the "planned outages" of the storage fields. ED staff determined that it was reasonable to assume that each well would be out of service for about 10 weeks, or 20 percent of the time, to account for both planned and unplanned outages percent. However, ED staff also investigated this assumption through sensitivity analysis.

## Withdrawal and Injection Capacity

Maximum withdrawal and injection curves were obtained from SoCalGas for all four storage fields. These curves describe the relationship between a field's storage inventory level and its maximum available withdrawal or injection capacity. These curves are mostly linear, while others are constant regardless of the inventory. These curves were implemented in the model as linear equations and are primarily used to compute the available injection and withdrawal capacity at a known inventory level. The curves have also been integrated to take the effect of decreasing or increasing capacity throughout the same day into account, though some stakeholders claim this change may be negligible.

## Injection and Withdrawal Sequence

ED staff made assumptions regarding which storage fields are used first and which storage fields are used last. Assuming that excess supplies are available to inject at any storage field, then the injection capacity becomes the only limitation on injection. Based on the most recent injection curves, injection time from zero inventory to full inventory was calculated. These are 176, 126, 107, and 26 days for La Goleta, Aliso Canyon (0 to 68.6Bcf), Honor Rancho, and Playa Del Rey. Therefore, for modeling purposes, any excess supplies were first injected into La Goleta (slowest field), followed by Honor Rancho, then Playa Del Rey, and lastly Aliso Canyon. Aliso Canyon was chosen last to minimize its use. The withdrawal sequence used was the same sequence used for injection, i.e. if there was an interstate supply deficit, natural gas was withdrawn first from La Goleta, followed by Honor Rancho, then Playa Del Rey, and lastly Aliso Canyon.

## Minimum and Maximum Inventory Levels

In the reliability assessment, ED staff assumed that the non-Aliso fields were at 90 percent inventory levels. To assess the reasonableness or feasibility of this assumption, ED staff implemented it as an artificial limit in the feasibility assessment model. For example, if the inventory level in La Goleta reached 90 percent, withdrawals were not allowed from it until its inventory increased above 90 percent again, and the following storage field in the withdrawal sequence was used. If the next storage field in the withdrawal sequence had also reached 90 percent (Honor Rancho for example), then it was not used, and the following field was used (Playa Del Rey) and so on until possibly all fields had been used or cycled through (once per day).

As for the maximum inventory limits, all non-Aliso fields were set to 100 percent of working gas inventory (i.e., full inventory capacity). Aliso Canyon was set at different maximum inventory levels ranging between 40 and 100 percent at 20 percent increments.

For each day in the simulation, if there was an excess of interstate supply (i.e. interstate supplies are higher than the demand), then the injection sequence was initiated, while always respecting the injection limits. For example, if the supplies were 3 Bcf and the demand was 2.5 Bcf, then 500 MMcf needed to be injected on that day. If La Goleta was not full (i.e. inventory <100 percent), and its average injection capacity on that day was, for example, 100 MMcfd, then 100 MMcf was injected into La Goleta as long as its inventory was not above 100 percent. The remaining 400 MMcf was injected into the other fields following the sequence described above and the same logic. If all fields used their maximum injection capacity or were full, or a combination thereof, but there was still excess gas, then that day was flagged as an EFO day. In actual operations, the pipeline operator would issue a high OFO in attempt to return the balance to the system. The EFO in the feasibility assessment model does not necessarily translate to an actual EFO since the operator can issue a high OFO and customers may attempt to voluntarily increase their gas use or decrease their deliveries in order to avoid penalties.

Similarly, if there was a deficit in interstate supplies (i.e. interstate supplies were lower than the demand), then the withdrawal sequence was initiated, while always respecting the withdrawal limits. For example, if the supplies were 3 Bcf and the demand was 4 Bcf, then 1 Bcf needed to be withdrawn on that day. If La Goleta was above its minimum allowed inventory level (e.g. 90 percent), and its average available withdrawal capacity on that day was, for example, 200 MMcfd, then 200 MMcf was withdrawn from La Goleta as long as the its inventory did not dip below 90 percent. Otherwise, a smaller amount was withdrawn until the final inventory volume was 90 percent. The remaining 800 MMcf (or more if La Goleta withdrawal was less than 200 MMcf) would then be withdrawn from the other fields following the sequence described previously and the same logic. If all fields were withdrawn from or reached their respective allowed minimum inventory level (or a combination thereof), but there was still a deficit in gas, then that day was flagged as an EFO day. In actual operations, the pipeline operator would issue a low OFO in an attempt to return the balance to the system. Again, the EFO in the feasibility assessment model does not necessarily translate to an actual EFO since the operator can issue a low OFO and customers may attempt to voluntarily decrease their gas use or increase their deliveries in order to avoid penalties.

Results will be presented in the next two sections, where the first section presents some preliminary results to introduce the model, and the second section presents the full parametric study that was performed. For all results, only low or positive EFOs are reported, i.e. days where the interstate supplies and the available withdrawals were not sufficient to meet the demand. High or negative EFOs were not a critical factor in determining the feasibility of the network-storage system.

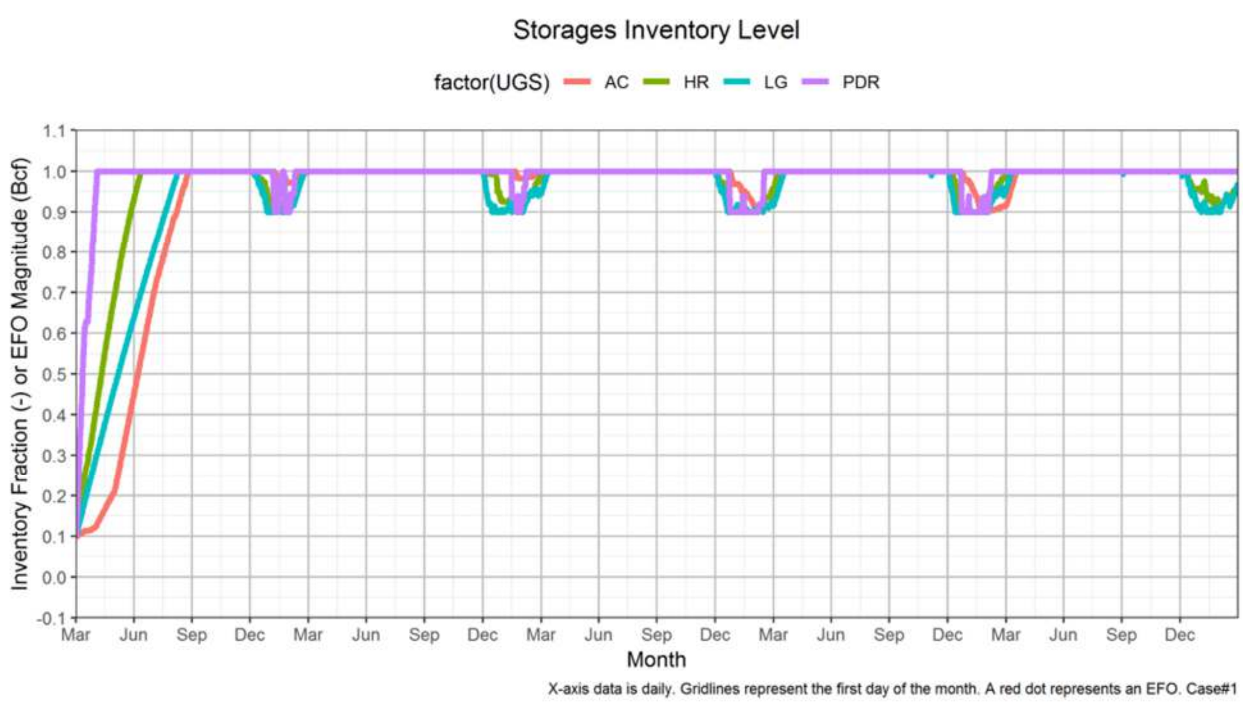
## Graphical Sample of Results

In this section, two scenarios will be presented: one that represents an ideal case scenario and one that represents a worst-case scenario. The ideal case scenario assumes a high value of interstate supplies (3,013.5 MMcfd), 100 percent well availability, 90 percent minimum inventory levels at the non-Aliso fields, 100 percent maximum inventory levels at all fields, low standard deviation (lower 95 percent confidence) during an average weather year (i.e. 1,320 HDD). The worst-case scenario assumes lower interstate supplies (2,613.5 MMcfd), 75 percent well availability, 90 percent minimum inventory levels at the non-Aliso fields, 100 percent maximum inventory levels at all fields, high standard deviation (upper 95 percent confidence) during a cold weather year (i.e. 1,594 HDD).

The results presented are primarily for the inventory tracking over the course of the study year 2020. Due to the random nature of the model, ED staff chose to run the simulation more than once in order to track potential inventory levels multiple times for the same study year. This is because the random draws made from each monthly distribution are not the same when the model is executed multiple times (as with any random draw). Therefore, the plots shown in this section will be for five repetitions of the study year 2020. To create a more statistically meaningful result, ED staff actually ran the model 50 times as will be shown later in the parametric study section.

The results of the ideal case scenario are shown in the next figure, where the x-axis represents the day of the year, but only the months' names are shown for clarity. The x-axis extends for five repetitions of the study year 2020. The y-axis represents two outcome variables. The first variable is the fraction of the inventory level in a storage field, with values ranging from zero to one (from 0 percent to 100 percent). These values are shown for the four storage fields in solid-colored lines (red for AC (Aliso Canyon), green for HR (Honor Rancho), cyan for LG (La Goleta), and purple for PDR (Playa Del Rey)). The second variable on the y-axis is the magnitude of the imbalance (or EFO) in Bcf (if it occurred) shown as red dots. The ideal case scenario did not produce any imbalance days or EFOs, so no EFO data is shown for this scenario.

Figure V - 5 Storage Inventory Level – Ideal Case



In the ideal scenario, the initial level of the gas inventory in all four storage fields was assumed to be at 0.1 (10 percent) at the beginning of March. The ideal case scenario shows that Playa del Rey was full by April, Honor Rancho was full by June, La Goleta was full by August, and Aliso Canyon was full before the end of August. Playa del Rey was filled first despite being third in the injection sequence because it is the smallest storage field. La Goleta was filled third despite being first in the injection sequence because it is the "slowest" field, i.e. it has a relatively smaller injection capacity. Aliso Canyon was filled last because it is fourth in the injection sequence while also being the largest storage field of all four. The inventory tracking shows that it was possible for all four storage fields to achieve 100 percent inventory level before the winter season and remain between 90 percent and 100 percent inventory level without triggering any imbalances throughout the winter season. The results also show that by the end of the winter season, the four storage fields were near 90 percent inventory levels.

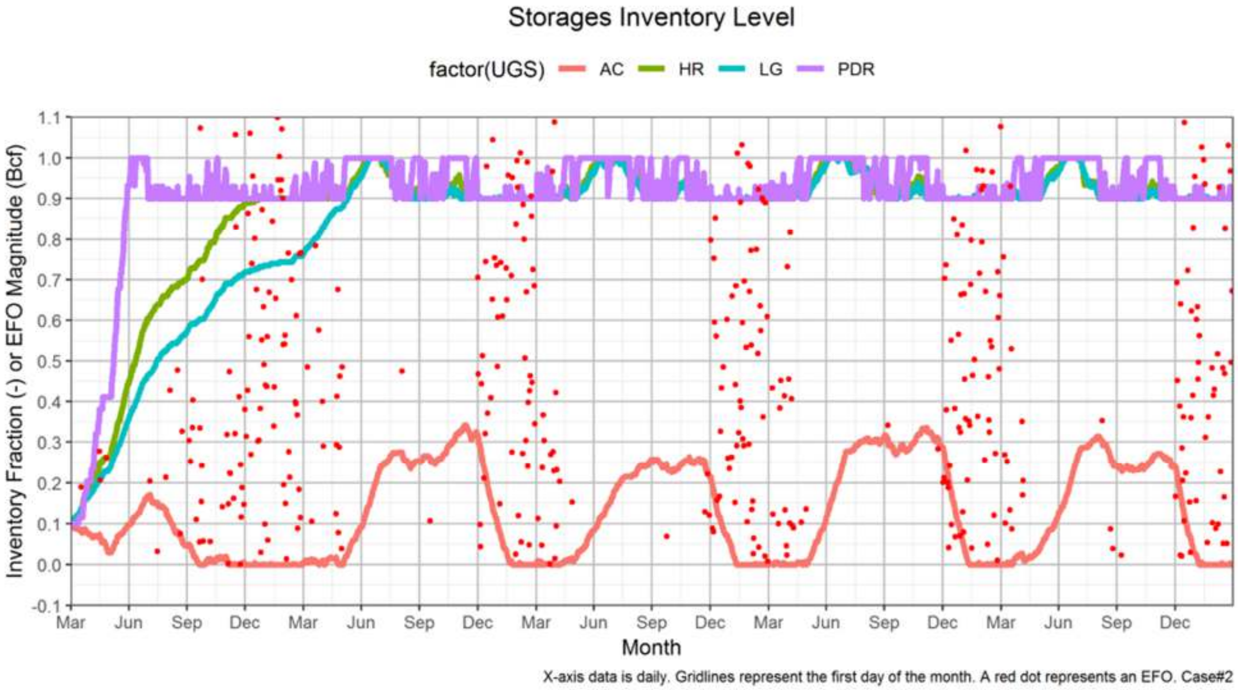
The results of a worst-case scenario are shown in the next figure. This scenario was selected to illustrate how the model works and to demonstrate how the input assumptions can affect the outcomes. The worst-case scenario starts with the same initial conditions as the ideal case scenario, i.e. 10 percent inventory level at the beginning of March, but with much lower interstate supplies (2,613.5 MMcfd), lower well availability (75 percent), and during a cold year.

The first apparent result is that Aliso Canyon was not filled to 100 percent. In fact, the peak inventory level in Aliso Canyon never exceeded 35 percent for all five repetitions of 2020. In the first repetition of study year 2020, Aliso Canyon was almost depleted before the beginning of the winter. This was chiefly because withdrawals were not allowed from the non-Aliso fields since their inventory levels had not yet reached their targeted minimum of 90 percent.

The results also show that Honor Rancho and La Goleta were not filled to the desired inventory level of 100 percent in the first repetition of study year 2020. In other words, if the inventory level of these two fields was actually at 10 percent in the beginning of the injection season, it would be difficult for the operator to fill them to 100 percent under the worst-case scenario assumptions. On the other hand, if the inventory levels were at 75-90 percent at the beginning of March (as is the case in the second repetition of year 2020), then it would be possible for those two fields to be filled to 100 percent.

It is also clear that during the winter season, many of the imbalance days (EFOs) occurred with varying magnitude as illustrated by the red scattered dots. The magnitude of the imbalance on some days is higher than 1 Bcf especially when the non-Aliso fields are at or below their minimum allowed inventory level of 90 percent. The results of the worst-case scenario demonstrate what an unfeasible scenario looks like.

Figure V - 6 Storage Inventory Level – Worse Case




## Parametric Study Results

Due to the numerous independent variables that could affect the outcome of the feasibility assessment as well as the uncertainty around them, ED staff designed and executed a parametric study in which some independent variables were varied within a range determined from the preliminary results, then the effects on the inventory levels and imbalance days were analyzed.

Based on the preliminary results, the following four independent variables were identified as critical and were assigned a range, rather than a single value:

1. Pipeline capacity or interstate supplies. Range: 2,700-3,100 MMcfd, with 100 MMcfd increments.
2. Well availability. Range: 60-100 percent, with 20 percent increments
3. Non-Aliso minimum allowed inventory. Range: 10-70 percent, with 20 percent increments.
4. Aliso maximum allowed inventory. Range: 40-100 percent, with 20 percent increments.

The combinations of the four independent variables resulted in 240 scenarios for the feasibility assessment (five values for pipeline capacity X three values for well availability X four values for non-Aliso minimum allowed inventory X four values for Aliso maximum allowed inventory = 240 scenarios), which were further analyzed. The parametric study was executed using a cold-weather year while repeating the inventory tracking for study year 2020 50 times.

Dependent values (outcomes), such as the number of EFOs or imbalance days were averaged over the 50 repetitions of the study year, which yielded the expected value of the yearly average of that value (outcome). The most important outcome from any of the 240 scenarios is the yearly average number of EFO days. As described earlier, if the gas system is unable to balance on a day (i.e. meet the demand based on the available interstate supplies and withdrawals), then that day is flagged as an EFO day. Only low EFOs are reported in the analysis.

To deem a scenario feasible, ED staff used the following criteria, which are based on the analysis of the preliminary results and the parametric study:

1. Criteria 1: Based on the feasibility assessment results:
    a. No EFOs were triggered, or
    b. EFOs were triggered but the average demand on the days when the EFOs were triggered was higher than 4,987 MMcfd (the 1-in-10 winter peak design day of study year 2020).
2. Criteria 2: Based on the reliability assessment results:
    a. A scenario's assumed maximum allowable inventory level of Aliso Canyon and minimum allowable non-Aliso inventory levels must satisfy the minimum levels assumed (non-Aliso fields) or needed (Aliso) from any *successful* 1-in-10 reliability simulation throughout the winter season.

For example, if the reliability assessment assumed non-Aliso inventory levels of 90 percent and resulted in 40 percent inventory needed from Aliso through a successful simulation, then this combination must also meet criteria "1," and the inventory levels for all fields must be maintained throughout the whole winter.

To explain some of results of the parametric study, a subset of the 240 scenarios is shown in the next figure, which illustrates the results of 16 scenarios. For these 16 scenarios, the values of the independent variables are:

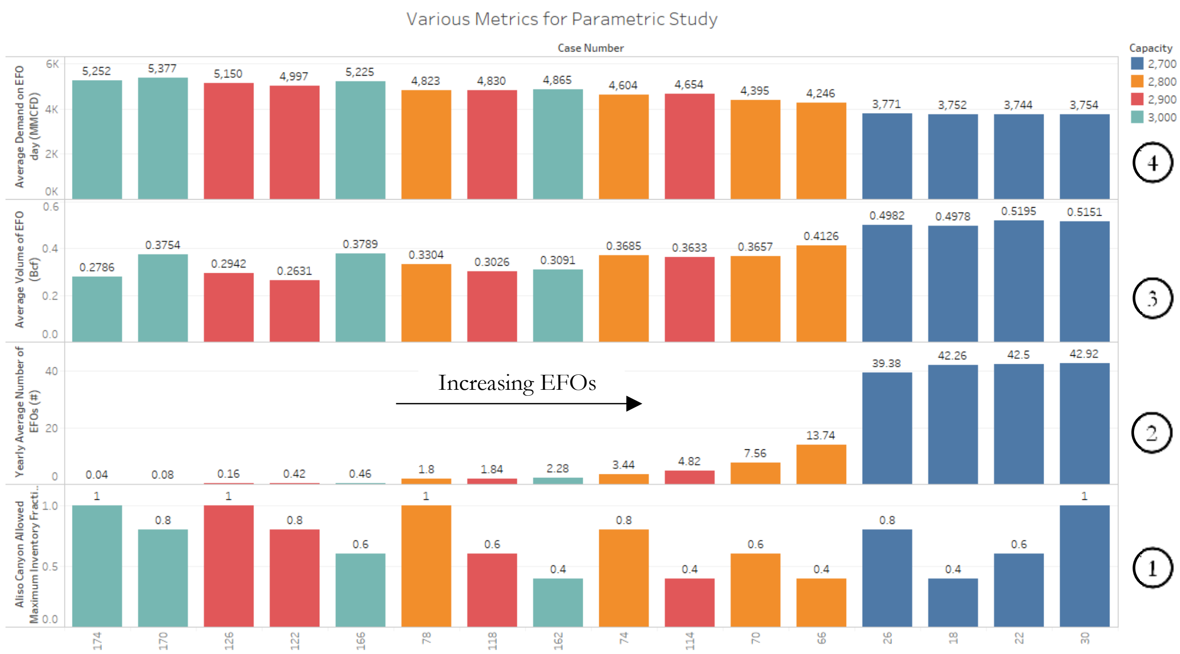
1. Pipeline capacity: 2,700, 2,800, 2,900, and 3,000 MMcfd (four values)
2. Well availability: 80 percent
3. Non-Aliso minimum allowed inventory: 30 percent
4. Aliso maximum allowed inventory: 40, 60, 80, and 100 percent (four values)

The figure consists of four bar charts where each chart shows a value of an independent or a dependent (outcome) variable for all 16 scenarios. The number on top of each bar is the value of that variable. The x-axis on the bottom shows the scenario number (case number), where the first scenario on the left is Scenario 174 and the last ($16^{th}$) scenario on the right is Scenario 30. The bar charts are colored by the pipeline capacity (blue for 2,700 MMcfd, orange for 2,800 MMcfd, red for 2,900 MMcfd, and cyan for 3,000 MMcfd). The figure is designed to be read *bottom to top* as follows:

1. The number below the bottom axis is the scenario (case) number (1-240)
2. Chart 1: Aliso maximum allowed inventory (an independent or input variable)
3. Chart 2: the expected yearly average number of EFOs (a dependent or outcome variable)
4. Chart 3: the magnitude of the Low EFO in Bcf (a dependent or outcome variable)
5. Chart 4: the expected average demand on days when EFOs were triggered (a dependent or outcome variable)

The bar charts are sorted in ascending order by the average number of EFOs, where the scenario with the lowest number of EFOs is on the left. The first scenario on the left is Scenario 174, which allows Aliso Canyon to be filled to 100 percent, assumes an interstate capacity of 3,000 MMcfd (cyan), results in a yearly average number of EFOs of 0.04 (i.e. two days in 50 repetitions of year 2020) and an average imbalance of 0.2786 Bcf on days with average demand of 5,252 MMcfd. Based on the criteria set previously, scenario 174 meets Criteria 1. In contrast, Scenario 66 (12th scenario from the left in the figure) allows Aliso Canyon to be filled to 40 percent, assumes an interstate capacity of 2,800 MMcfd (orange), results in a yearly average number of EFOs of 13.74, with an average imbalance of 0.4126 Bcf on days with average demand of 4,246 MMcfd. Based on the criteria set above, Scenario 66 is not feasible (Criteria 1 failed).

Figure V - 7 Parametric Study Metrics




EFO.demand.MMCFD, EFO.mean.volume, EFO Count and Aliso Canyon Allowed for each Case Number. Color shows details about Capacity. For pane EFO.demand.MMCFD: The marks are labeled by EFO.demand.MMCFD. For pane EFO.mean.volume: The marks are labeled by EFO.mean.volume. For pane EFO Count: The marks are labeled by EFO Count. For pane Aliso Canyon Allowed: The marks are labeled by Aliso Canyon Allowed. The data is filtered on Wells Availability, Aliso Canyon Allowed, Non-Aliso Minimum and Capacity. The Wells Availability filter keeps 0.8. The Aliso Canyon Allowed filter keeps 0.4, 0.6, 0.8 and 1. The Non-Aliso Minimum filter keeps 0.3. The Capacity filter keeps 2700, 2800, 2900 and 3000.

This subset of scenarios also illustrates how a pipeline capacity of 2,700 MMcfd (blue) is unfeasible regardless of the other independent parameters. Scenarios 26, 18, 22, and 30, which assume a pipeline capacity of 2,700 MMcfd, are all unfeasible. These four scenarios result in an average number of EFOs of 39-43 per year (Criteria 1 failure). In fact, all 48 scenarios that included a 2,700 MMcfd interstate capacity are unfeasible (not shown in figure, but part of the parametric study). This is because the pipeline capacity of 2,700 MMcfd is lower than the average daily demand required during a cold year, which is 2,743 MMcfd. The jump in the number of EFOs between these scenarios and the other 192 scenarios adds to the confidence in the model used for the feasibility assessment.

Based on the figure above, ED staff concludes that scenarios 174, 170, 126, 122, and 166 meet criterion "1". The remaining 11 scenarios are all unfeasible. These five scenarios will be used later to provide the results regarding the maximum allowed inventory for Aliso Canyon.

Of all 240 scenarios included in the parametric study, 157 scenarios did not meet Criterion 1 set above, while 83 scenarios met it. It is noteworthy that all combinations containing both an Aliso

Canyon inventory of 40 percent and non-Aliso fields inventories at 70 percent were not feasible. Therefore, ED staff deduced that maintaining non-Aliso fields at 70 percent or higher is not feasible. Based on the full parametric study, ED staff concluded the following:

1. For the well availability range considered in the parametric study (60-100 percent), Aliso Canyon allowed maximum inventory (40-100 percent), and interstate supplies less than or equal to 2,900 MMcfd, a minimum allowed inventory of non-Aliso fields of 70 percent or higher is not feasible (36 scenarios).
    a. If interstate supplies are increased to 3,000 MMcfd, a 70 percent minimum inventory level at the non-Aliso fields may be feasible, but only if Aliso is allowed to be filled to 100 percent.
    b. If interstate supplies are increased to 3,100 MMcfd, a 70 percent minimum inventory level at the non-Aliso fields may be feasible, but only if Aliso is allowed to be filled to 60 percent.
2. At **100 percent well** availability year-around, a **50 percent minimum** allowed inventory of non-Aliso fields is:
    **a. Unfeasible** if interstate supplies are less than or equal to 2,800 MMcfd regardless of Aliso Canyon maximum allowed inventory.
    **b. Feasible** if Aliso Canyon is allowed to be filled to 100 percent, and interstate supplies are greater than or equal to 2,900 MMcfd.
    **c. Feasible** if Aliso Canyon is allowed to be filled to 60 percent, and interstate supplies are greater than or equal to 3,000 MMcfd.
    **d. Feasible** if Aliso Canyon is allowed to be filled to 40 percent, and interstate supplies are greater than or equal to 3,100 MMcfd.
3. At **80 percent well** availability year-around, a **50 percent minimum** allowed inventory of non-Aliso fields is:
    **a. Unfeasible** if interstate supplies are less than or equal to 2,900 MMcfd regardless of Aliso Canyon maximum allowed inventory.
    **b. Feasible** if Aliso Canyon is allowed to be filled to 60 percent, and interstate supplies are greater than or equal to 3,000 MMcfd.
    **c. Feasible** if Aliso Canyon is allowed to be filled to 40 percent, and interstate supplies are greater than or equal to 3,100 MMcfd.
4. At **60 percent well** availability year-around, a **50 percent minimum** allowed inventory of non-Aliso fields is:
    **d. Unfeasible** if interstate supplies are less than or equal to 2,900 MMcfd regardless of Aliso Canyon maximum allowed inventory.
    **e. Feasible** if Aliso Canyon is allowed to be filled to 80 percent, and interstate supplies are greater than or equal to 3,000 MMcfd.
5. At **100 percent well** availability year-around, a **30 percent minimum** allowed inventory of non-Aliso fields is:
    **f. Unfeasible** if interstate supplies are less than or equal to 2,800 MMcfd regardless of Aliso Canyon maximum allowed inventory.
    **g. Feasible** if Aliso Canyon is allowed to be filled to 60 percent, and interstate supplies are greater than or equal to 2,900 MMcfd.

    h. **Feasible** if Aliso Canyon is allowed to be filled to 40 percent, and interstate supplies are greater than or equal to 3,000 MMcfd.

6. At **80 percent well** availability year-around, a **30 percent minimum** allowed inventory of non-Aliso fields is:
    a. **Unfeasible** if interstate supplies are less than or equal to 2,800 MMcfd regardless of Aliso Canyon maximum allowed inventory.
    b. **Feasible** if Aliso Canyon is allowed to be filled to 80 percent, and interstate supplies are greater than or equal to 2,900 MMcfd.
    c. **Feasible** if Aliso Canyon is allowed to be filled to 60 percent, and interstate supplies are greater than or equal to 3,000 MMcfd.
    d. **Feasible** if Aliso Canyon is allowed to be filled to 40 percent, and interstate supplies are greater than or equal to 3,100 MMcfd.
7. At **60 percent well** availability year-around, a **30 percent minimum** allowed inventory of non-Aliso fields is:
    e. **Unfeasible** if interstate supplies are less than or equal to 2,800 MMcfd regardless of Aliso Canyon maximum allowed inventory.
    f. **Feasible** if Aliso Canyon is allowed to be filled to 100 percent, and interstate supplies are greater than or equal to 2,900 MMcfd.
    g. **Feasible** if Aliso Canyon is allowed to be filled to 8% percent, and interstate supplies are greater than or equal to 3,000 MMcfd.

Based on the analysis of the full parametric space, ED staff concluded that the interstate supplies are the strongest factor affecting the feasibility assessment outcomes, and therefore the allowed inventory at Aliso Canyon. Well availability has an impact and will slightly affect the allowed inventory, but only if both extreme values are compared (i.e., 60 vs. 100 percent well availability). Based on the expected planned maintenance on wells, 80 percent well availability is an appropriate assumption and will be used to provide the results of the Aliso Canyon maximum allowed inventory. Well availability values within the 70-90 percent range are unlikely to have a marked effect on the allowed inventory.

As for the feasible non-Aliso minimum allowed inventory levels, these are strongly tied to interstate supplies and Aliso Canyon maximum allowed inventory, which again renders the interstate supplies the main driving factor of the feasibility assessment. The results of the parametric study show that higher non-Aliso minimum allowed inventory levels are feasible only when higher interstate supplies are available, while also requiring a higher inventory level at Aliso Canyon, which contradicts the goal of SB 380 to minimize or eliminate Aliso Canyon. In fact, this is an expected outcome, since a minimization of the use of Aliso Canyon would directly result in a "maximized" use of the non-Aliso fields. This in turn would require them to drop below the levels assumed in the reliability assessment (90 percent winter, 70 percent for the summer).

In terms of hydraulics, the role of Aliso Canyon is two-fold. First, Aliso Canyon must maintain a certain minimum withdrawal capacity during the winter, which was analyzed in the reliability assessment. The reliability assessment showed that a minimum of 520 MMcfd withdrawal capacity must be maintained to meet a 2030 1-in-10 peak design day, when 90 percent inventory levels at the non-Aliso fields and 3,115 MMcfd of pipeline supplies were assumed. However, the feasibility assessment shows that a 90 percent inventory level at the non-Aliso fields is unfeasible during a cold year and will result in more imbalance days. The feasibility assessment shows that non-Aliso storage fields will, and should, drop to at least 30 percent to make their withdrawal capacities available throughout a cold winter (see slides 31-36 in Workshop 4[4]). It is not clear how the operator can maintain a 90 percent level in the non-Aliso fields. For example, if the non-Aliso fields are at a 90 percent inventory level and the forecast shows that a 1-in-10 peak day is about to occur, then the operator would have to withdraw from all fields without a guarantee that those fields would be replenished the next day or even for the remainder of the winter season.

The second role of Aliso Canyon is to actually "store" natural gas for when interstate supplies are scarce, whether it is due to upstream multi-state disturbances, production shortages, or pipelines outages. In order for Aliso Canyon to maintain a 520 MMcfd withdrawal capacity (which corresponds to a roughly 40 percent inventory level), it must do so for most of the winter season. Therefore, the withdrawal capacity of Aliso Canyon at the beginning of the season must be higher than the level required to ensure 520 MMcfd of withdrawal capacity (i.e., an inventory level higher than 40 percent). For this reason, the parametric study range of Aliso Canyon inventory level was set from 40 to 100 percent and did not consider any level below 40 percent.

The parametric study shows that if the non-Aliso fields are not allowed to drop below a 90 percent inventory level, then the outcome is more withdrawals (reliance) on Aliso Canyon (to maintain the non-Aliso inventory level at 90 percent) and therefore a higher inventory level at Aliso Canyon. The recommended Aliso Canyon inventory levels, which are described in the next section, strike a balance between maintaining the required withdrawal capacity from Aliso Canyon by the end of the winter while minimizing its use (inventory level).

## Staff Results for Aliso Canyon Storage Level

As concluded in the previous section, interstate supplies are the strongest factor affecting the outcome of the feasibility assessment and therefore the Aliso Canyon maximum allowed inventory. There is currently considerable uncertainty regarding the level of interstate pipeline capacity that will be available on the SoCalGas system in the coming years. Hence, staff provides several values based on different assumptions about the availability of interstate supplies, which are summarized in the following table.

Table V - 3 Storage Level Results

| Daily Pipeline Capacity | Percentage of CalGEM Approved level for Aliso | Maximum Allowable Inventory in Aliso | Number of EFO days | Average Demand on EFO days |
|---|---|---|---|---|
| MMCFD | percent | Bcf | # | MMCFD |
| 2,700 | 100 percent | 68.6 | 42.92 | 3,754 |
| 2,800 | 100 percent | 68.6 | 1.8 | 4,823 |
| 2,900 | 80 percent | 54.88 | 0.42 | 4,997 |
| 3,000 | 60 percent | 41.16 | 0.46 | 5,225 |

Based solely on the reliability and feasibility assessments of the SoCalGas pipeline and storage system, Energy Division staff presents the following maximum allowed inventories at Aliso Canyon as among the range of possible limits to set in the proceeding:

1. For interstate supplies of 2,800 MMcfd or less, which corresponds to current SoCalGas firm pipeline capacity, the limit would be 100 percent of the inventory allowed by CalGEM or 68.6 Bcf. Energy Division Staff notes, however, that these interstate supplies are so low that the reliability of the system may not be preserved even with 100 percent maximum allowable inventory at Aliso Canyon. This is because EFOs or imbalance days occur on days when the demand is below the 1-in-10 demand level.
2. For interstate supplies around 2,900 MMcfd, 80 percent of the inventory allowed by CalGEM or 54.88 Bcf is sufficient to meet the standard.
3. For interstate supplies around 3,000 MMcfd, 60 percent of the inventory allowed by CalGEM or 41.16 Bcf is sufficient to meet the standard.

Available pipeline capacity and interstate supplies have been a major dispute among all stakeholders, which is evident by the comments on the Scenarios Framework version 1,[30] version 2,[31] and version 3[32] during Phase I of this proceeding. In addition, ED Staff analysis showed that the receipt point utilization, which is a proxy for available supplies, tended to decrease on high demand days, though it was not clear if this decrease was due to economics or scarce interstate supplies caused by multi-state cold events. The table below, which was presented in workshop 1[33] and in the hydraulic modeling clarifications document,[34] summarizes stakeholders input regarding the receipt point utilization.

Table V - 4 Stakeholder Input Regarding Receipt Point Utilization

| Party | Proposed RPU | Notes |
|---|---|---|
| Herbert S. Emmrich | Not 85% | Use peak demand days data |
| LA County | 85%-100% | Analyze historical data |
| Environmental Defense Fund | 85% | 95% when demand > 4Bcfd |
| Issam Najm | 90% | |
| Public Advocates Office | 85% | Only for Winter. Need analysis of Summer. |
| Southern California Edison | 85% | But need high demand days to be analyzed |
| The Utility Reform Network | | Sensitivity with RPU < 85% |
| SoCalGas | 60%-80% | As per historical data |

- In the final framework, CPUC suggested 85% RPU for the Northern and Southern zones, and 100% for the Wheeler Ridge zone. CPUC also included a sensitivity at 100%.

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[30] https://www.cpuc.ca.gov/general.aspx?id=6442454071
[31] https://www.cpuc.ca.gov/general.aspx?id=6442457997
[32] https://www.cpuc.ca.gov/general.aspx?id=6442459294
[33] https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/Hydraulic%20Modeling%20Updates%20Final%202019_06_20.pdf
[34] https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2020/FurtherHydraulicModelingClarifications-05272020.pdf

Based on ED Staff analysis and stakeholders' input, the reliability assessment scenarios assumed 85 percent utilization, which resulted in about 3,115 MMcfd of available interstate supplies. On the other hand, the feasibility assessment included a range of pipeline capacity from 2,700 to 3,100 MMcfd. The reliability assessment assumed that only unplanned outages will be present on a peak day design. In contrast, the feasibility assessment must assume both planned and unplanned outages, and therefore a value smaller than 3,115 MMcfd, which is the upper bound of the range considered in the parametric study.

## Conclusions

ED Staff note and conclude the following:

1. The Reliability Assessment results indicate that Aliso Canyon **is needed to preserve the reliability** of the gas-electric system on a **1-in-10 peak design day** for all study years (2020, 2025, and 2030).
2. The Reliability Assessment results indicate that **520 MMcfd** of withdrawal capacity from Aliso Canyon is needed on a winter 2030 peak day with a **90 percent inventory** level at the non-Aliso fields and **3,115 MMcfd** of interstate supplies assumed.
3. The Sensitivity Analysis for the 2030 peak design day show that the need for Aliso Canyon withdrawals could be as much as **1,160 MMcfd** should the levels in the non-Aliso fields drop to **37 percent**.
4. The Reliability Assessment results indicate that **Aliso Canyon may not be needed** to preserve the reliability of the gas system on a **1-in-35 peak design day** while also meeting the minimum local demand of electric generators, although that level of electric generation curtailment has significant consequences for the electric system.
5. The Feasibility Assessment was performed for a cold 2020 year, and the results indicate that the inventory level needed at Aliso Canyon is **60-100 percent depending on the available interstate supplies**, where a higher inventory level is needed when interstate supplies are lower.
6. The Feasibility Assessment results suggest that **100 percent inventory at Aliso Canyon** is needed when interstate supplies are **2,800 MMcfd or less**. The results indicate that inventory levels of **80 percent or 60 percent** could be sufficient to consistently meet the standard if interstate supplies increase to **2,900 MMcfd or 3,000 MMcfd** respectively.
7. SoCalGas has offered **2,715 MMcfd** of firm capacity in the 2020 open season for Backbone Transmission System capacity compared to the 3,875 MMcfd that was offered in 2017. This reduction of 1,160 MMcfd is mainly due to a loss of 600 MMcfd from the Northern Zone due to sustained outages and a loss of 460 MMcfd from the Southern Zone due to changes in demand configuration. SoCalGas indicated that:
    a. SoCalGas plans to complete remediation work on Line 4000 in the Northern Zone by September 2021, which would increase its receipt capacity, although not to its historic level.
    b. The receipt capacity on the Southern Zone is primarily a function of local demand rather than total system demand plus available injection capacity.

c. Reduced demand on the Southern Zone will be treated as an indefinite maintenance outage that will limit firm BTS offerings available under a **minimum demand condition.**
d. Additional Southern Zone receipt capacity will be offered on a daily basis during periods when higher local demand is expected.
e. Thus, only 750 MMcfd of firm capacity was offered for the Southern Zone in 2020. The remaining capacity of 460 MMcfd was offered as "interruptible."

1) Uncertainty in the regulatory environment and future investment opportunities in both the gas and the electric sector are among the factors driving the uncertainty in the availability of interstate supplies. Hence, a range of results is presented rather than a fixed value.

# Appendix A - Data Request Summary

## Objective

CPUC Energy Division submitted nine data requests and associated follow-ups to SoCalGas between October 2017 and September 2020. The majority of the responses contain confidential information which is not available through other sources. Staff gathered this data in order to conduct hydraulic modeling of the SoCalGas system. The following tables list the data request numbers, follow-up numbers, dates issued, topics, sub-topics, and response dates.

## Data Request Listing

Table VI- 1 Data Request Topics and Response Dates

| Data Request | Follow - Up # | Date Issued | Topic | Sub-topic | Response Date |
|---|---|---|---|---|---|
| 1 | | 10/11/2017 | 1. Customer Demand and Flows | 1. Gas usage forecast by zip code for core and small noncore customers. Usage forecast by customer for large noncore customers, including electric generation and wholesale customers | 11/3/2017 |
| | | | | 2. Usage forecast for the above for a cold winter day (1 in 10) and an extreme cold winter day (1 in 35) | |
| | | | | 3. Date range (year or month) applicable to the forecasts. For electric generation customers, usage forecast for forecasted peak summer day, or if not available, usage data for most recent peak historical summer day. | |
| | | | 2. Infrastructure Info | 1. Map of Transmission System | |
| | | | | 2. Pipeline Segment Data | |
| | | | | 3. Receipt Points | |
| | | | | 4. Storage Fields | |

| Data Request | Follow - Up # | Date Issued | Topic | Sub-topic | Response Date |
|---|---|---|---|---|---|
| | | | | 5. Compressor Stations | |
| | | | | 6. Regulator/Valve Stations | |
| | | | 3. Planned Upgrade and Retirement Info | Ventura Compressor Station | |
| 2 | not used | | | | |
| | | | | | |
| | | | | | |
| 3 | | 12/17/2018 | Infrastructure and Forecasts | Infrastructure Info | 1/19/2019 |
| | | | | Hourly Demand Forecasts | |
| | | | | Winter Withdrawal Curves | |
| | | | | Compressor Stations<br>Pipeline and Receipt Point Locations | |
| | 1 | 1/22/2019 | Modeling Methodologies (response date not listed; response did not add any new information) | | |
| | 2 | 6/19/2019 | Synergi Case File | Above info in native Synergi format | 11/22/2019 |
| | | | | for Simulation-1 Winter 2020 | |
| | 3 | 2/13/2020 | Excel workbooks matching Synergi Case File | Nodes, Pipes, Profiles, Summer Nodes, Summer Profiles, Zip Codes & Nodes | 2/20/2020 |
| | 4 | 2/21/2020 | Modeling Methodology | 1. Explain reason for excluding facilities from model for simplification and how this might affect simulation results.<br>2. How were hourly gas demand profiles developed?s<br>3. How were gas demand by nodes developed?<br>4. How are minimum operating pressures of pipes computed? Why is summer different than winter?<br>5. How is Maximum Operating Pressure calculated from maximum allowable operating pressure (MAOP)? | 3/6/2020 |

| Data Request | Follow - Up # | Date Issued | Topic | Sub-topic | Response Date |
|---|---|---|---|---|---|
| | | | | Provide MAOP by pipe segment. | |
| | 5 | 5/21/2020 | MOP and Winter MinOP data | Explain why some pipes have disparate MOP or MinOP. | 5/28/2020 |
| | S01 | 11/1/2019 | Simulations: results of SoCalGas using Synergi to run Simulations 1-9 | Simulation 01 Winter 2020 1-in-10 | 12/9/2019 |
| | S02 | 4/23/2020 & checklist 4/29/2020 | | Simulation 02 Summer 2020 1-in-10 | 5/22/2020 |
| 3 | S03 | 4/23/2020 & checklist 5/13/2020 | | Simulation 03 Winter 2025 1-in-10 | 5/29/2020 |
| | S04 | 4/23/2020 & checklist 5/29/2020 | | Simulation 04 Summer 2025 1-in-10 | 6/12/2020 |
| | S05 | 4/23/2020 & checklist 6/12/2020 | | Simulation 05 Winter 2030 1-in-10 | 7/8/2020 |
| | S06 | 4/23/2020 & checklist 6/24/2020 | | Simulation 06 Summer 2030 1-in-10 | 7/13/2020 |
| | S07 | 9/17/2020 | | Simulation 07 Winter 2020 1-in-35 | 10/8/2020 |
| | S08 | 9/17/2020 | | Simulation 08 Winter 2025 1-in-35 | 10/9/2020 |
| | S09 | 9/17/2020 | | Simulation 09 Winter 2030 1-in-35 | 9/18/2020 |
| 4 | | 2/5/2019 | Outages and Maintenance | Planned and unplanned outage detail (nine years: 1/1/10 to 12/31/18) | 2/15/2019 |
| | | | | Historic ENVOY Maintenance Notices | 3/29/2019 |
| | | | | Estimated scheduled maintenance in 2020 | 4/19/2019 |
| 5 | | 3/15/2019 | AMI Data - Hourly Gas Demand Profiles, Historical Load | 1. Hourly gas demand (burn) profiles by zip code for 10% of each customer class (AMI = Advanced Metering Infrastructure) | 4/3/2019 |

| Data Request | Follow - Up # | Date Issued | Topic | Sub-topic | Response Date |
|---|---|---|---|---|---|
| | | | | 2. Table relating customer ID to class, subclass and zip code | |
| | | | | 3. Historical and forecasted connected natural gas load by customer class, zip code and end use for 2017-2020, 2025 and 2030. | |
| | 1 | 4/19/2019 | Customer Billing Data | Gas demand profiles for 10% of each customer class by zip code. | 7/18/2018 |
| 5 | A | 9/20/2019 | Historical counts of AMI-enabled customers | by zip code and customer class | 10/9/2019 |
| | B | 10/18/2019 | Meter data for SDG&E | | 11/19/2019 |
| | C | 2/21/2020 | Request for additional data, reconciliation of responses with Data Request 6. | | 3/23/2019 |
| 6 | | 3/20/2019 | Daily Sendout Data | 1. Daily sendout data for core and non-core customers. Forecast, actual, and estimated actual sendout. Scheduled receipts. Withdrawal, withdrawal capacity. Injection capacity, system receipt capacity, firm capacity, interruptible capacity. | 5/24/2019 and follow-ups 6/20/2019, 8/9/2019 |
| | | | | 2. Operation Flow Orders (OFO) and Emergency Flow Orders (EFO). Date, imbalance, high or low, cycle, state, tolerance. | 6/20/2019, 8/9/2019 |
| | | | | 3. Storage Inventory | 5/24/2019 and follow-ups 6/20/2019, 8/9/2019, 8/20/2019, 9/13/2019 |
| | | | | 4. Residential Customer counts by zip code by type, disconnections | 5/24/2019 and follow-ups 8/9/2019, |

| Data Request | Follow - Up # | Date Issued | Topic | Sub-topic | Response Date |
|---|---|---|---|---|---|
| | | | | | 8/20/2019, 9/13/2019 |
| | | | | 5. Core Customer counts by zip code by type, disconnections | 5/24/2019 and follow-up 8/9/2019 |
| 6 | | | | 6. Noncore Customer counts by zip code by type, disconnections | 5/24/2019 and follow-up 8/9/2019 |
| | | | | 7. Monthly and Daily Usage (post AMI meter installation) for CARE and non-CARE households by zip code, for area overlapping SCE and PG&E territories. | 5/24/2019 and follow-up 8/9/2019 |
| | | | | 8. variation on # 7 | 5/24/2019 |
| | | | | 9. Monthly distribution info about CARE customers by zip code. Procurement and transportation charges, usage volume by month. Mean, median, min, max, standard deviation. | 5/24/2019 |
| | | | | 10. Same as #9, for non-CARE customers. | 5/24/2019 |
| | | | | 11. Daily actual and forecasted temperatures by zip code. Also system average actual and forecasted temperature. | 5/24/2019 |
| | | | | 12. Daily curtailment by end user customers. Date, core or non-core, customer class | 6/20/2019 |
| 7 | | 3/22/2019 | SoCalGas Envoy website data | Daily available gross capacity, nominated and scheduled quantities for 1/1/2005 to the present. | 3/29/2019 |
| 8 | | 5/15/2020 | Maps showing pipeline MAOPs (Maximum Allowable Operating Pressures) | 1. Ten miles downstream of each compressor station. | 6/5/2020 |
| | | | | 2. Five miles downstream of each receipt point | 6/5/2020 |
| | | | | 3. Ten-mile radius around each of the four underground storage fields | 6/5/2020 |

| Data Request | Follow - Up # | Date Issued | Topic | Sub-topic | Response Date |
|---|---|---|---|---|---|
| | | | | 4. Five-mile radius around the five city gates | 6/5/2020 |
| 8 | | 6/25/2020 | | Confirming reduced and full MOP for 20 pipes; clarify crossovers upstream | 7/6/2020 |
| | 1 | 9/3/2020 | | Clarifications | 9/17/2020 |
| 9 | | 5/18/2020 | SCADA (Supervisory Control and Data Acquisition) data | 1. Date range of historical data | 5/26/2020 |
| | | | | 2. SCADA software program | 5/26/2020 |
| | | | | 3. Format of historical data - raw or processed | 5/26/2020 |
| | | | | 4. Format used to store and archive | 5/26/2020 |
| | | | | 5. Natural gas properties, pipeline properties, ambient or soil properties tracked and recorded (e.g. pressure, flow rate, volume meters, temperature, mass fraction) | 5/26/2020 |
| | | | | 6. Approximate count of each sensor, particularly transmission pipeline data, receipt points and pressure regulators. | 5/26/2020 |
| | 1 | 6/16/2020 | Historical SCADA data for specified properties and locations. | Summary of sensors used to provide data. | 7/7/2020 |