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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Investigation pursuant to Senate Bill 380 to determine the feasibility of minimizing or eliminating the use of the Aliso Canyon natural gas storage facility located in the County of Los Angeles while still maintaining energy and electric reliability for the region.	Investigation 17-02-002

ADMINISTRATIVE LAW JUDGE'S RULING REQUESTING INFORMAL FEEDBACK ON ENERGY DIVISION'S UPDATED PROPOSED PHASE 1 SCENARIOS

Summary

Pursuant to the June 20, 2017 Scoping Memo and Ruling of [the] Assigned Commissioner and Administrative Law Judge (Scoping Memo), with schedule updated by ruling on May 23, 2018, this ruling provides parties with the California Public Utilities Commission's (Commission) Energy Division Update to the Scenarios Framework (Updated Proposal) for feedback and discussion at an upcoming workshop.

Informal comments on the Updated Proposal must be served (but not filed) by close of business June 28, 2018 and sent to Commission staff at AlisoCanyonOII@cpuc.ca.gov. A workshop to discuss the Updated Proposal will be noticed in a separate ruling; however, it is tentatively scheduled for July 31, 2018 in the Los Angeles area.

Energy Division's Updated Proposal

Affixed to this ruling as Attachment A, parties will find Energy Division's *Update to the Scenarios Framework: Investigation (I.) 17-02-002* (Updated Proposal). The Updated Proposal was developed pursuant to the direction of the June 20, 2017 Scoping Memo and Ruling of [the] Assigned Commissioner and Administrative Law Judge (Scoping Memo) and incorporating informal feedback received from parties after issuance of Energy Division's Initial Proposed Phase 1 Scenarios Framework (issued on June 26, 2017, Initial Proposal) and a subsequent workshop held on August 1, 2017.

As described further in the Update Proposal, Energy Division, with reliance on its internal modeling team and Los Alamos National Laboratory, has updated and refined each of three proposed models (hydraulic, economic, and production cost) that, together, will inform this Order Instituting Investigation. As stated in the Updated Proposal, "the models are intended to demonstrate whether or not Aliso Canyon Natural Gas Facility (Aliso) is needed for reliability and what the impact on costs would be if Aliso were to be closed or operated at a level of inventory lower than historic norms."[1]

As stated in the June 26, 2017 Ruling introducing the Initial Proposal, "the intent of the overall proposal development, comment and workshop process is to allow parties and Energy Division to work together so that Energy Division may develop a comprehensive proposal on models, scenarios and puts that can be used to inform the Commission's decision…"[2] By issuance of the Updated

[1] Updated Proposal at 4.

[2] Administrative Law Judge's Ruling, June 26, 2017, at 3.

Proposal, Energy Division seeks to further solicit the feedback parties so that the models can be developed in as transparent as possible so that parties, no matter their resources, can use modeling results to develop their own arguments on the future of Aliso.

The Commission's Energy Division seeks informal feedback of parties on its Updated Proposal and the questions contained therein. Parties are invited to serve, but not formally file, informal comments on the Updated Proposal by close of business June 28, 2018. Parties should also send their comments to the Commission's Energy Division staff at AlisoCanyonOII@cpuc.ca.gov. Informal comments will not become part of the formal record in this proceeding. Energy Division will use the informal comments to inform discussion with parties at the second workshop, tentatively scheduled for July 31, 2018 in the Los Angeles Area. A formal ruling confirming the date, time and location of the second workshop will be issued subsequent to this ruling.

After review of informal comments and feedback from parties at the second workshop, Energy Division will create a final proposal, which will be entered into the record of this proceeding. At that time, parties may provide formal comments on the final proposal, and those comments will be incorporated into the record of this proceeding.

IT IS RULED that:

1. The California Public Utilities Commission's Energy Division *Update to the Scenarios Framework: Investigation (I.) 17-02-002* (Updated Proposal) is attached to this ruling as Attachment A. Parties are invited to serve, but not file, informal comments on the Updated Proposal, as well as responses to the questions contained in the Updated Proposal, by close of business June 28, 2018. Parties should also send informal comments to the California Public Utilities

Commission Energy Division staff at the following email address: AlisoCanyonOII@cpuc.ca.gov. Informal comments will not become part of the formal record of this proceeding.

Dated June 15, 2018, at San Francisco, California.

/s/ JESSICA T. HECHT for
Melissa K. Semcer
Administrative Law Judge

Update to the Scenarios Framework: I.17-02-002

June 15, 2018

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Introduction

In this document, the California Public Utility Commission's (CPUC or Commission) Energy Division (ED) updates its June 26, 2017, framework for conducting the studies needed to inform the Ordering Instituting Investigation (OII) 17-02-002. The OII will determine whether use of the Aliso Canyon natural gas storage facility (Aliso) can be minimized or eliminated. The models are intended to demonstrate whether or not Aliso is needed for reliability and what the impact on costs would be if Aliso were to be closed or operated at a level of inventory lower than historic norms. The inputs into the models will be based on demand projections that incorporate all the increases in renewables, conservation, and energy efficiency currently required by California legislation.

This update to the Scenarios Framework builds on the comments received on the first version, both in written form and at the August 1, 2017, workshop. The section on hydraulic modeling also benefits from Energy Division's consultation with Los Alamos National Laboratory (Los Alamos). This version is not final. Energy Division will be holding a second workshop on July 31, 2018, during which parties will have the chance to vet the proposed scenarios and assumptions and to provide additional input. Parties to the proceeding also have the opportunity to make informal comments on this framework in advance of the first workshop. Informal comments are due by June 28, 2018, and should be emailed to the service list of Investigation (I.) 17-02-002 (but not formally filed) and sent to Commission staff at AlisoCanyonOII@cpuc.ca.gov.

Background

A major gas leak was discovered at the Southern California Gas Company's (SoCalGas) Aliso Canyon natural gas storage facility on October 23, 2015. On January 6, 2016, the governor ordered SoCalGas to maximize withdrawals from Aliso to reduce the pressure in the facility. 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 was approved. Among other things, the bill:

1. Prohibited injection into Aliso until a safety review was completed and certified by the Division of Oil, Gas, and Geothermal Resources (DOGGR) 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, the CPUC opened an Order Instituting Investigation pursuant to SB 380. The proceeding is structured to take place in two phases. In Phase 1, the Commission will undertake a comprehensive effort to develop the appropriate analyses and scenarios to evaluate the impact of reducing or eliminating the use of Aliso. The intent of Phase 1 is to involve all interested parties in developing a transparent and vetted list of assumptions and scenarios. Phase 1 will be resolved by the issuance of an Assigned Commissioner's Ruling providing guidance on the scenarios and assumptions that will be evaluated in Phase 2. In Phase 2, the Commission will conduct the analyses agreed to in Phase 1 and evaluate their results. These results will inform the Commission's decision on the appropriate use of the storage field.

On July 19, 2017, DOGGR certified, and the Executive Director of the Commission concurred, that the required inspections and safety improvements had been completed and injections could resume. DOGGR authorized Aliso to operate at pressures between a minimum of 1,080 pounds per square inch absolute (psia) and a maximum of 2,926 pounds psia.[1] These pressures translate into an allowable inventory of working gas that ranges from 0 Bcf to approximately 68.6 Bcf.[2] Any decision about Aliso inventory ultimately reached in I.17-02-002 would need to fall within the DOGGR-approved range.

Modeling Overview

Energy Division plans to undertake three studies to inform this investigation: hydraulic modeling, production cost modeling, and economic modeling. The studies are intended to estimate how reducing or eliminating use of Aliso would impact gas and electric reliability, electric costs and reliability, and natural gas commodity costs, respectively.

Energy Division will conduct the production cost modeling and economic modeling in-house, and has hired Los Alamos National Security LLC (Los Alamos) to provide technical assistance and oversee the hydraulic modeling study to be performed by SoCalGas. Los Alamos has overseen hydraulic modeling performed by SoCalGas for

[1] http://www.conservation.ca.gov/dog/Documents/Aliso/Enclosure1_2017.7.19_Updated%20Comprehensive%20Safety%20Review%20Findings.pdf

[2] This figure is based on an April 19, 2018, email from DOGGR to the CPUC.

previous versions of the Aliso Canyon Technical Assessments.[3] Los Alamos has assisted Energy Division in updating the hydraulic modeling section of this Framework. Los Alamos will work with Energy Division to provide expertise on the final scenarios to be modeled and assumptions about the gas system. Los Alamos will also review the technical interpretation of hydraulic modeling scenarios to be performed by SoCalGas and prepare recommended modifications to SoCalGas modeling.

Hydraulic Modeling

In principle, analysis of the coupled electric grid-natural gas system in Southern California requires a fully integrated, intra-day model of the two systems. This type of integrated modeling is not commercially available and is not feasible to develop in the time available to complete the required analysis for the current proceeding. Instead, a scenario framework is constructed to evaluate key reliability and feasibility requirements of the individual natural gas and electric power systems and to define how the output of each infrastructure model is used to develop boundary conditions or inputs for the other model.

The key analysis task is the determination of the minimum level of gas in underground storage needed to maintain reliability of both energy systems and to maintain just and reasonable energy rates. In this analysis, preference is given to operations of non-Aliso Canyon storage facilities to determine the minimum need for gas storage inventory at Aliso Canyon. If the minimum level of inventory is found to be zero, then analysis concludes that the closing of Aliso would not affect the coupled energy system reliability.

The framework considers two operational elements:

- Relative to gas prices for core and non-core gas customers, the traditional role of gas storage at Aliso Canyon is to leverage seasonal variations in gas prices to store significant quantities of gas near the load centers while gas prices are low and to release that gas to customers during periods of high prices.

[3] The Technical Assessments were created by the Aliso Canyon Technical Assessment Group, which consists of the CPUC, the California Energy Commission, the California Independent System Operator, and the Los Angeles Department of Water and Power and began in response to the Aliso gas leak. All previous versions of the Technical Assessments can be found at: http://cpuc.ca.gov/alisoassessments/.

- Relative to gas system reliability, the role of gas storage at Aliso Canyon is twofold:
    - When daily gas load is higher than the pipeline flowing capacity, gas is withdrawn from storage at Aliso to serve the load that exceeds flowing supply. This functionality is possible because Aliso is close to the major gas load centers and the incremental gas added from Aliso withdrawals does not compete with the flowing supply for pipeline transportation.
    - When daily gas load is highly variable, rapid increases or decreases in the hourly gas load can cause large pipeline pressure swings. Withdrawals from or injections into Aliso Canyon can be used to mitigate these swings to keep the pressure within operating bounds—a critical requirement for maintaining safety and avoiding excessively low pressures from limiting gas flows.

Within this framework, the joint energy system is first analyzed for reliability. After the Reliability Assessment is complete, the resulting gas system and electric system characteristics may be analyzed for impacts on the cost of energy services, as discussed in the Economic Modeling section.

The Reliability Assessment may return a result that does not meet the required natural gas delivery performance, even when implementing the full set of allowable operational actions; therefore, a Feasibility Assessment will also be completed as part of the hydraulic modeling. The Feasibility Assessment will determine if the monthly minimum storage volume targets determined by the Reliability Assessment can be maintained throughout the year.

Proposed Scenarios

Near Term, Medium Term, and Long Term

ED proposes that the analysis take a graded approach. In a graded approach, a full monthly analysis will be completed for 2019 to provide near term gas storage targets. In later years, i.e. 2024 (5 years) and 2029 (10 years), the Reliability Assessment should be run for the peak Winter and peak Summer months. These will provide model results indicating the lowest minimum storage requirement at Aliso Canyon to ensure system reliability for SoCalGas customers.

Reliability Assessment Overview

Reliability Standard and Associated Conditions

A key feature of a reliability assessment is the definition of one or more reliability standards. Within the context of this study, these reliability standards represent severe operating conditions that are not expected to occur frequently, i.e., the 1-in-10-year and 1-in-35-year scenarios discussed later in this report. Each of these standards define two important conditions for the SoCalGas natural gas system:

- The required performance of the natural gas delivery system
- The operational actions that are allowable to achieve this performance.

The natural gas system is held to two related reliability standards that differ in the severity of the gas loading and the flexibility in curtailments.

- 1-in-10 Year Analysis—No curtailment of any gas load (core; non-core, non-electric; or non-core, electric) is allowed in the analysis. Core and non-core, electric gas loads are estimated based on a 1-in-10 year peak statistics. Non-core, electric gas loads are estimated from normal operations of the electric grid.
- 1-in-35 Year Analysis—Curtailment of all non-core gas load is acceptable. Core gas loads are based on 1-in-35 year peak statistics.

The full implementation of all operational actions is likely to stress other systems connected to the SoCalGas system, which is not a desirable outcome. However, the concept of designing to, or analysis of, a reliability standard assumes that this cascading stress on the connected system is acceptable. With this understanding, the Reliability Assessment of the SoCalGas system will use full implementation of all allowable operational actions to achieve the required system performance.

The assessment of the reliability standards is done using simulation of the infrastructure system under the conditions of the 1-in-10 peak day design standard. This should not be confused with analysis of a historical operating day. In real world conditions, the system operators do not have the foresight of upcoming conditions that is available in the simulation assessment of the reliability standard. The simulation assessment of the reliability standard should not be interpreted as an “operational playbook” that informs the system operators of each action they should take. In actual operations, even in a scenario similar to what is defined in the reliability standard, the system operators may take additional actions, not take actions that were taken in the analysis, or implement actions in a different order.

These differences between real-world operations and the simulation of the reliability standard may be important to the final outcome of the SoCalGas system delivery performance and to the cascading stress applied to connected systems. The Reliability Assessment only shows that it is *possible* to achieve the minimum gas system performance standard without implementing operational actions beyond that which is allowable by the standard.

Potential Analysis Beyond the Reliability Assessment

The Reliability Assessment may return a result that does not meet the required natural gas delivery performance, even when implementing the full set of allowable operational actions. In this case, a sensitivity analysis may be performed to estimate what additional actions may be taken beyond the set of operational actions defined by the reliability standard.

Reliability Assessment Outline

A high-level outline of the Reliability Assessment is composed of the following steps:

- **Base Gas Load Profiles**—For the natural gas system, hourly load profiles are defined for the highly stressed operating conditions, i.e., the expected peak day for each month of the simulated year(s). The total load profile is determined from its three constituents:
    - Core gas load
    - Non-core, non-electric gas load
    - Non-core, electric gas load
- **Gas Curtailments**—For the peak day conditions, the maximum allowable gas load curtailment is defined for each constituent
- **Gas System Modeling**—The natural gas pipeline and storage system is modeled for the peak day and the required hourly withdrawals from underground storage facilities are determined accordingly:
    - Withdrawals from non-Aliso facilities is utilized first
    - If non-Aliso facilities cannot support the total load, then withdrawals from Aliso are used to serve the remaining gas load that is not allowed to be curtailed in the scenario
- **Minimum Gas Storage Requirement** — Facility-specific curves of maximum withdraw rate versus gas storage are used to convert the required gas storage withdraw rates at each facility to a minimum gas storage volume requirement to maintain reliability during the scenario

- **Aggregation**—Completing this analysis for each month of the year determines a "Minimum Gas Storage Schedule" for each time period studied (all of 2019, peak summer and winter months of 2024 and 2029), at each gas storage facility.

This outline only provides a high-level summary of the Reliability Assessment. Each step requires several inputs, assumptions about those inputs, and may involve multiple models or model types. The remainder of this report provides details on each of these steps.

Feasibility Assessment Outline

As stated previously, the Reliability Assessment only determines the minimum monthly inventory targets for underground storage at each facility to support the required SoCalGas system performance under the stressed conditions of the reliability standard. The Reliability Assessment does not provide information on whether those minimum storage targets are feasible to achieve. The next step in the analysis of the natural gas system is a Feasibility Assessment. The gas system hydraulics are simulated under nominal conditions to determine the available capacity for injections at the SoCalGas storage facilities and if the Minimum Gas Storage Requirement from the Reliability Assessment can be met. A high-level outline of the Feasibility Assessment is composed of the following steps:

- **Base Gas Load Profiles**—For the natural gas system, hourly load profiles are defined for the nominal operating conditions, i.e., the nominal operating day for each month of the simulated year(s). The total load profile is determined from its three constituents:
    - Core gas load
    - Non-core, non-electric gas load
    - Non-core, electric gas load
- **Gas System Modeling**—The natural gas pipeline and storage system is modeled for the nominal day in each month. Any available excess gas system capacity is used to support injections into underground storage. Gas storage withdrawals are used to eliminate deficits in gas system flow supply relative to load or to provide systems balancing. If the available injection capacity (minus required withdrawals) are sufficient to meet the required gas storage monthly minimums determined in the Reliability Assessment, the Minimum Gas Storage Schedule is deemed feasible.

This outline only provides a high-level summary of the Feasibility Assessment. Each step requires several inputs, assumptions about those inputs, and may involve multiple models or model types. As seen in Figure 1, the Feasibility Assessment is the last step of the hydraulic modeling. The remainder of this report provides details on each of these steps.

Figure 1: Hydraulic Modeling Steps

Reliability Standards

For each month, either the 1-in-10 Year Analysis or the 1-in-35 Year Analysis will result in a higher withdrawals from gas storage. The higher of the two is used to determine the Minimum Gas Storage Requirement.

Determining if reliability standards are met will be based on the following inputs and curtailment assumptions:

Base Gas Load Profiles

Core gas load

- 1-in-10: Most recent California Gas Report or directly from SoCalGas
- 1-in-35: Most recent California Gas Report or directly from SoCalGas

Non-core, non-electric gas load

- 1-in-10: Most recent California Gas Report or directly from SoCalGas
- 1-in-35: Most recent California Gas Report or directly from SoCalGas

Non-core, electric gas load

- 1-in-10: Economic optimal production cost model with no gas supply constraints and meeting minimum NERC reliability standards
- 1-in-35: Out-of-merit production cost model that reduces gas consumption to the minimum to meet NERC reliability standards

Gas Curtailments

Core gas load

- 1-in-10: None
- 1-in-35: None

Non-core, non-electric gas load

- 1-in-10: None
- 1-in-35: Full curtailment to zero, while maintaining certain carve outs as specified in Rule 23

Non-core, electric gas load

- 1-in-10: None—This implies that the electric production cost model is unconstrained by gas availability
- 1-in-35: Full curtailment to zero—This implies that the electric production cost model should not allow any consumption of natural gas for electric generation under this scenario

Gas System Modeling for Reliability

After the peak load conditions and gas curtailment flexibility is known, the gas system model for the Reliability Assessment still requires several inputs, including: non-Aliso gas storage facility maximum withdrawal capabilities, achievable flowing gas supplies at the pipeline receipt points, and pipeline or storage outages that may affect the hourly send out of the gas system.

Non-Aliso Gas Storage Facilities

Each of these facilities is unique and is operated in a specific manner for the greatest benefit to the gas system:

- Playa Del Rey (PDR)—The PDR storage field has relatively small storage capacity, but it is key to gas control operations and reliability of gas supply in the Los Angeles Basin during a day of peak gas send out. These storage field operations are reflected in both the 2017 Summer system capacity study and in actual gas control operations. PDR has relatively short refill time (approximately a few days); therefore, PDR can be considered be at maximum storage capacity and can supply the corresponding maximum withdrawal rates on any peak day.[4]
- La Goleta—The La Goleta storage field has access to limited pipeline transportation capacity. On peak-day operation, pipeline constraints limit the ability of this storage field to support peak gas loads to the south in the Los Angeles Basin. This field is used in more of a "base load" manner to support the overall recovery of system-wide "linepack[5]", but any peaking storage withdrawal from this field is used primarily to support peak gas loads in the coastal region of the SoCalGas pipeline system. This use is reflected in both the 2017 Summer system capacity study and in actual gas control operations. Because of the pipeline restrictions near La Goleta, assuming that La Goleta is at

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[4] If alternative scenarios are considered that span more than one day, the availability of maximum withdrawal rates at PDR come into question and this assumption should be revisited.

[5] Storing gas in the pipeline as opposed to within a storage facility

maximum storage capacity and maximum withdrawal rates on any peak day are limited by pipeline transportation constraints.

- Honor Rancho—Compared to La Goleta, the Honor Rancho storage field has better access to pipeline transportation capacity into the Los Angeles Basin. It is key to supporting peak gas loads in the Los Angeles Basin; however, the full withdrawal capacity of Honor Rancho may not be achievable because the withdrawal from Honor Rancho storage competes with gas receipts from Wheeler Ridge for pipeline transportation capacity. If both Honor Rancho storage withdrawal and Wheeler Ridge receipts are maximized, pipeline pressure would exceed maximum allowable operating pressures, which would violate safety and compliance requirements. Under the stressed conditions of the Reliability Assessment, it is reasonable to assume that the combination of Wheeler Ridge receipts and Honor Rancho withdrawals will always be pipeline transportation limited, and the available aggregate supply from these sources can is determined by this limit.
- Aliso Gas Storage Facility—The Reliability Assessment is computing the required withdrawals from Aliso; therefore, no assumptions about the gas storage is required.

Flowing Gas Supplies at the Receipt Points

Under the stressed conditions of the Reliability Assessment, we anticipate the flowing supplies at the receipt points are maximized to minimize the withdrawals from storage, including Aliso. Hydraulic modeling can identify the maximum gas supply that could be scheduled into the SoCalGas pipeline system. Here, scheduling happens before actual gas system operations and control. In real-time operations, the scheduled flowing supplies may not be achievable, and differences between scheduled and actual deliveries must be taken into account.

In the 2017 Summer system capacity study, the assessment team investigated the daily actual versus scheduled gas imbalance data under the tighter gas balancing requirements in place during and following the Technical Assessment Group's Action Plan released in 2016[6]. The investigation of these limited data suggested that there is a

[6] The Aliso Canyon Action Plan to Preserve Gas and Electric Reliability for the Los Angeles Basin can be found here: http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Action_Plan_to_Preserve_Gas_and_Electric_Reliability_for_the_Los_Angeles_Basin.pdf

typical imbalance, with total actual gas receipts 10% less than total scheduled gas. This value reflects 90% utilization of scheduled receipts, a value that is within SoCalGas's historical annual average imbalance. The root cause of the imbalance has not been investigated in detail; however, discussions between SoCalGas and the Independent Review Team for the 2017 Summer system capacity study suggested that it is related to conservative scheduling by gas shippers, driven by the potential for penalties imposed during a high operational flow order if the shipper brings more gas on the SoCalGas system than was actually scheduled.

An additional analysis was performed that was not included in the 2017 Summer Reliability Assessment. This study was restricted to 2016 Summer days when SoCalGas implemented a low operational flow order. The results show that total actual deliveries to the SoCalGas system were 5% more than the scheduled gas deliveries. Follow up analysis to the 2017 Summer Assessment concluded that a deficit of 5% relative to the maximum available scheduling capacity (as determined by hydraulic modeling) at the receipt points was reasonable assumption during stressed operating conditions. For the scenarios considered here, the hydraulic modeling should consider this same 5% deficit relative to maximum available scheduling capacity.

Outages

Both pipeline and storage outages can significantly impact the ability of the natural gas system to serve load on peak days. The months with the most severe operating conditions are well known, and planned outages can usually be scheduled to occur outside of these months. However, unplanned outages are frequent enough that they must be accounted for in the gas system modeling for the Reliability Assessment. A key factor is the number of concurrent unplanned outages on a peak day, the location of these outages, and the severity of the outages. For the Reliability Assessment, we propose that gas pipeline system be subject to a single plausible unplanned outage (pipeline or storage) that results in the maximum loss of aggregate gas send out.
The determination of the plausible unplanned pipeline and storage outage events should be completed by SoCalGas based on historical records. A related analysis was carried out by SoCalGas and presented in Table 3 of the 2016 version of the Aliso Canyon Risk Assessment Technical Report[7].

[7] Aliso Canyon Risk Assessment Technical Report, April 2016 version: http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Risk_Assessment_Technical_Report.pdf

Under the stressed conditions of the Reliability Assessment, the impact of different unplanned outages can be estimated and ranked using the engineering judgement developed in Section 2.5 of the Independent Review of the Southern California Gas Hydraulic Modeling performed for the Summer 2017 Assessment. The discussion from that review is incorporated here by reference.

The logic of the Reliability Assessment suggests that unplanned outages should first be applied at non-Aliso components.

- If the Reliability Assessment concludes that withdrawals from Aliso Canyon are not required, then the analysis is complete.
- If the Reliability Assessment concludes that withdrawals from Aliso Canyon are required, then the impact of the largest plausible unplanned outage at Aliso Canyon must be assessed. Based on the required Aliso withdrawal rate:
    - If the largest plausible Aliso Canyon unplanned outage is smaller than the impact on gas delivery from the largest plausible non-Aliso outage—the non-Aliso outage dominates—then the analysis is complete.
    - If the largest plausible Aliso Canyon unplanned outage is larger than the impact on gas delivery from the largest plausible non-Aliso outage, the Aliso outage dominates. The Aliso outage is imposed and the non-Aliso outage removed when assessing the Aliso Canyon minimum required storage inventory to support the minimum required injections from Aliso Canyon.

Minimum Gas Storage Requirement

The gas system modeling outputs the required hourly withdrawals from non-Aliso and Aliso gas storage facilities to meet the dominant of the two reliability standards—1-in-10 Year Analysis or the 1-in-35 Year Analysis—for every month studied. The Reliability Assessment gives priority to withdrawals at non-Aliso facilities in an attempt to minimize the need for the Aliso facility. At each facility except for PDR[8], this required hourly withdrawal rate is converted into a required gas storage volume using the maximum withdrawal rate curves generated through a calibration process carried out by SoCalGas during operation of these facilities[9].

[8] The storage volume at PDR is small enough that, with appropriate forecasting and gas operations, PDR will be at maximum capacity when needed for a highly stressed day.

[9] These maximum withdrawal rate curves should be updated periodically. Any significant change in these curves should trigger a review of the Reliability Assessment.

In certain months of the year when the monthly peak day does not highly stress the gas system, the required withdrawals at Aliso may be zero, and the required withdrawal rates at La Goleta and Honor Rancho may fall below the assumed available minimums for each storage facility, discussed above. This does not violate the assumptions of the Reliability Assessment. It provides the relevant data on the required withdrawals while minimizing the need for the Aliso facility for reliability.

Feasibility Standards

A Feasibility Assessment may be carried out to determine if the monthly minimum storage volume targets determined by the Reliability Assessment can be maintained throughout the year.

The Reliability Assessment was carried out under highly stressed conditions to determine if the system could maintain adequate gas delivery performance during these infrequent scenarios. In contrast, the Feasibility Assessment is carried out under "typical" or "nominal" system conditions, defined on a monthly basis, to assess the nominal <u>available</u> gas storage injection rates and any associated withdrawal rates that may be required in nominal monthly operation. These monthly nominal injection/withdrawal rates are then used to determine if the monthly storage volumes are feasible to achieve.

A key assumption of the analysis framed here is that the stressed conditions imposed in the Reliability Assessment are infrequent, or that they are (on average) balanced out by abnormally mild system conditions, and do not significantly impact the total storage volumes over a several month time frame.

Determining if feasibility is met will be based on the following inputs and curtailment assumptions:

Base Gas Load Profiles

- *Core gas load*—Expected or average <u>daily</u> core gas load profile for each month of the analysis year from the most recent California Gas Report or directly from SoCalGas
- *Non-core, non-electric gas load*— Expected or average daily core gas load profile for each month of the analysis year from the most recent California Gas Report or directly from SoCalGas

- *Non-core, electric gas load*—The daily gas consumption profiles from a year-long electric production cost model are averaged within each month of the year to define the expected or average daily non-core, electric gas load. The electric production cost modeling in the next section will be performed without constraints on gas availability so that the electric generation is committed and dispatched to achieve economically optimal operations while maintaining NERC reliability standards.

Gas Curtailments

- *Core gas load*—None
- *Non-core, non-electric gas load*—None
- *Non-core, electric gas load*—None

Gas System Modeling for Feasibility

After the monthly average gas loads are known, the gas system model for the Feasibility Assessment still requires several inputs, including: behavior of the gas storage facilities, flowing gas supplies at the receipt points, and pipeline or storage outages that may affect the hourly send out of the gas system.

Gas Storage Facilities

Each of these facilities is unique and is operated in a specific manner for the greatest benefit to the gas system[1]:

- Playa Del Rey (PDR)—The PDR storage field has relatively small storage capacity, but it may still be key to gas balancing within the Los Angeles Basin for nominal operations during certain months of the analysis year. PDR's small storage capacity means that it cannot be continually drawn down. In the nominal monthly day of the Feasibility Assessment, PDR must start and end the day with the same quantity of stored gas, i.e., injections and withdrawals must be balanced on a daily basis for a nominal day. This "nominal day balance" condition is used for PDR in the Feasibility Assessment instead of a monthly minimum gas storage target.
- Non-PDR Gas Storage—La Goleta, Honor Rancho and Aliso Canyon can all support consistent net withdrawals or net injections over the monthly period in the Feasibility Assessment. In the Feasibility Assessment, for each month of the analysis year:
    - If there is excess gas system capacity to support net injections, the net injections in the hydraulic model are distributed across the non-PDR

facilities to: 1) ensure all facilities are at least above their required monthly minimums from the Reliability Assessment and 2) to maximize the total gas stored in aggregate fleet of storage facilities.

- If gas storage net withdrawals are needed, the net withdrawals in the hydraulic model are distributed across the non-PDR facilities to: 1) ensure that all gas loads are met without imposing curtailments and 2) to ensure that all facilities are at least above their required monthly minimums from the Reliability Assessment.

Flowing Gas Supplies at the Receipt Points

Similar to the Reliability Assessment, i.e., the flowing supply available at the receipt points is assumed to be 5% lower relative to the maximum available scheduling capacity at the receipt points (as determined by hydraulic modeling).

Outages

In contrast to the Reliability Assessment, the Feasibility Assessment must consider planned and unplanned pipeline and storage outages. Both types of outages occur under nominal operating conditions and impact the average ability to inject natural gas into storage or reduce the average flowing supply which may increase the demand for storage withdrawals. For the Feasibility Assessment, we propose that each gas pipeline system model (one model per month of the year) be subject to reductions in flowing supply and reductions in storage operations that are consistent with expectations from historical the historical record of these outages. Such an analysis was carried out by SoCalGas and presented in Table 3 of the 2016 version of the Aliso Canyon Risk Assessment Technical Report. If insufficient data exist to determine the expected planned and unplanned outages monthly, the expected outages may be determined on a yearly basis and the same outages applied in each of the 12 monthly gas system models.

Drawing Conclusions from Monthly Gas Injection/Withdrawal Schedules

The gas storage net injections and net withdrawals from the hydraulic modeling are for a nominal day for each month of the analysis year. These injections/withdrawals are integrated over each day of the month to compute the gas storage volume at the start of the next month. If the simulated storage volumes at each facility are above the Minimum Gas Storage Schedule determined from the Reliability Assessment, the gas system scenario is deemed feasible.

In conclusion, the graded approach to the Hydraulic Model will result in a total of 32 scenarios modeled as determined by various inputs to produce reliability and feasibility assessments towards determining the minimum Aliso Canyon requirement. This total amount of 32 consists of running each month in 2019 through normal and stressed operating conditions, as well as running the peak summer and winter months in 2024 and 2029 through normal and stressed operating conditions. These scenarios will result in the largest minimum storage requirement at Aliso Canyon.

If the scenarios are found to be greater than zero, then Aliso Canyon must remain open in those years, unless some alternative supply is added (flowing supply or other form of storage) or some alternative operational actions are allowed that reduce the minimum storage requirement at Aliso Canyon to zero. This analysis of the two peak months in the out years provides an answer to the key question of this analysis, i.e., if Aliso Canyon can be shut down in those years.

Production Cost Modeling

Energy Division proposes to perform Production Cost Modeling (PCM) analysis in coordination with the hydraulic modeling Reliability Assessment. This PCM analysis will fit in to provide necessary inputs to the Reliability Assessment in the hydraulic modeling as well as test the effects on electric system reliability and production costs that are the result of gas limitations found by the Reliability Assessment. If needed, studies can be done iteratively in order to fully determine how to minimize reliance on Aliso Canyon gas storage availability and to achieve the objectives of the study.

Energy Division staff has developed a standard process for completing PCM analysis to support the Resource Adequacy (RA) and Integrated Resource planning (IRP) proceedings. This document is referred to as the "Unified Inputs and Assumptions for RA and IRP PCM Modeling" (Unified I/A) and is available on the CPUC website.[10] The Unified I/A provides the general outline for PCM modeling, with modeling processes and conventions, as well as a description of the datasets that make up the base case.

In general, the Unified I/A document contains a description of the specific modeling software currently used (Strategic Energy Risk Valuation Model or SERVM) and the key datasets and data sources for use in the SERVM model. The Unified I/A also describes

[10] Document is linked to the CPUC website here:
http://www.cpuc.ca.gov/General.aspx?id=6442451972

the modeling process of performing stochastic reliability studies in a determined order based on Loss of Load Expectation (LOLE) and Effective Load Carrying Capability (ELCC) metrics.

In addition to general guidelines related to PCM modeling, Energy Division proposes some assumptions unique to the PCM modeling in this OII. In addition to the economic buffering effects of nearby gas storage on core and non-core gas prices, Aliso also provides either extra stored gas when demand is higher than flowing supply, or the ability to react to volatile gas pressures at various nearby delivery points with greater speed and flexibility than would otherwise be the case. Both these effects are important to the electric system, and to capture the effects of the removal or minimized use of the Aliso storage field, assumptions need to be made about how to reflect the absence of nearby stored gas on the operations of power plants within a PCM framework.

Aliso Canyon provides nearby gas supply and delivery to a 17 natural gas-fired power plants in the Los Angeles basin (Aliso Plants). The plants' nameplate capacity ranges from 45 MW to 1970 MW, with an average of 441 MW. Drawing down or eliminating the use of Aliso storage will reduce the rate of gas delivery to the Aliso Plants. This will affect the plants' ramping ability, ability to start up on short notice, and other operating parameters, which in turn will affect the electric system's costs and reliability. In addition, under the 1-in-35 design standard scenario adopted in SoCalGas Tariff Rule 23, complete curtailment of a larger group of electric generators may become required to protect core customer gas supply.[11]

Finally, several data inputs and outputs from the PCM analysis will feed into the hydraulic modeling analysis. In particular, the expected hourly dispatch of electric generators at various points of the SoCalGas gas transmission system over the course of the peak design standard days in question will be used to model the flow and pressure on network elements that the hydraulic model will need to simulate.

Given these PCM effects, Energy Division proposes to evaluate:

- What is the effect of reducing or eliminating use of Aliso on the total system production cost and reliability of the electric grid?

[11] SoCalGas Tariff Rule 23 is linked here: https://www.socalgas.com/regulatory/tariffs/tariffs-rules.shtml

- What is the effect of curtailment imposed by Rule 23 in a 1-in-35 design standard peak day on electric generators?
- At what impairment of gas flows from Aliso is there resulting levels of reliability impact (measured in total expected Loss of Load Expectation (LOLE)) and cost impact (measured in rise in expected system production cost from dispatching alternative electric generation) that are significant and intolerable to stakeholders?

PCM Analysis Plan

PCM modeling will be conducted with the SERVM model, developed by Astrapé Consulting. SERVM simulates least-cost dispatch for a user-defined set of generating resources and loads. It calculates numerous reliability and cost metrics for a given study year considering expected weather, overall economic growth, and performance of the generating resources. More detail regarding source and calculation of the modeling inputs, as well as their use in the SERVM model, are specified in the Unified I/A.

Energy Division will use the SERVM model and the assumptions developed in the Unified I/A to simulate electric generation dispatch and create a proposed 1-in-10 reliability standard day as well as a 1-in-35 winter gas demand day, and also simulate expected electric dispatch in a 1-in-10 summer peak day. These electric generation profiles will be created from annual dispatch simulations and will represent the probability weighted average 24-hour dispatch values, from different classes of plants, calculated to produce the 24-hour day profile representative of the expected Peak Winter and Peak Summer months as needed for the hydraulic modeling Reliability Assessment.

Energy Division staff will alter the dataset in certain specific ways to simulate the scenarios under consideration in the Aliso OII. Energy Division will restrict the operation of the 17 power plants linked to Aliso Canyon (Aliso Plants) in both the CAISO and LADWP system to simulate the effect of more distant gas delivery. In the event of Aliso closure, gas for these power plants will need to be scheduled well in advance, to allow for delivery from a distant gas delivery hub. Energy Division staff proposes to simulate this effect in SERVM by restricting the ramp rate and increasing the startup up time and extending the startup profile of the Aliso Plants.

Energy Division will also seek to simulate the effect of a Rule 23 curtailment on a 1-in-35 peak winter day by attaching power plants across the SoCalGas system to a single gas source and setting total gas delivery limits on the power plants to reflect limits resulting from the hydraulic model Reliability Assessment 1-in-35 Peak Winter Day modeling.

In both cases, Energy Division staff will look for effects in terms of production cost and reliability level that are significantly escalated. The steps of the modeling process are briefly described below.

- Perform a "As Found" PCM study to determine reliability and cost of the existing system without any changes made in the three study years of 2019, 2024 and 2029. The study will be similar to the study that Energy Division is performing for the IRP proceeding as described in the Unified I/A document. This is meant to represent a system unconstrained by natural gas curtailment and represent the 1-in-10 Peak Winter and Peak Summer day dispatch levels.
- Develop forecasted hourly generation profiles based on the hourly results of the "As Found" study for the set of generating plants in the SoCalGas system, grouping generators by delivery point to provide input to the Reliability Assessment in the hydraulic model.
- Staff will oversee and evaluate the hydraulic modeling Reliability Assessment. The results of that assessment will inform constraints to place on power plants related to Aliso Canyon curtailment.
- Receive and implement any curtailment information from the Reliability Assessment for the 1-in-35 Peak Winter day, as well as any curtailment to the Aliso Plants. Rerun the As Found study and identify any changes to LOLE or total production costs. Likely changes to each metric will be the result of changes in unit dispatch, where either less useful or more expensive generation is dispatched in place of the Aliso Plants.
- Report results to stakeholders and determine if the effects of Aliso curtailment or removal are significant enough to warrant evaluation of any planned action regarding the Aliso gas storage field.

Proposed Scenarios

Near Term, Medium Term, and Long Term

As a starting point, Energy Division recommends answering the above questions for the years 2019, 2024, and 2029. These years provide an estimate of the effects of Aliso closure on the short, medium, and long term. Although years beyond 2029 could be forecast, substantial uncertainty exists about the state of the grid in those years, making the outputs of such an analysis less useful.

Aliso Inventory Level

Energy Division proposes beginning the modeling process using the Aliso inventory level recommended by the CPUC in its "Section 715 Report", which determines the range of Aliso inventory necessary to ensure safety, reliability, and just and reasonable rates .[12] If that inventory level is too low to ensure a minimum acceptable level of grid reliability and total system production costs, Energy Division will gradually increase Aliso inventory until an acceptable level is reached in the PCM model. If the level determined by the 715 report is unnecessarily far above minimum acceptable levels needed for electric grid reliability and total system production costs, Energy Division will gradually lower inventory until that acceptable level is reached. It is important to determine the minimum acceptable level, which requires iterative PCM runs until an optimal outcome is reached.

Desired Reliability Levels

The SERVM model requires that the user specify constraints on tolerable reliabilities. Energy Division proposes to use the standard from the Resource Adequacy proceeding as a constraint in the modeling, a maximum of one LOLE (Loss of Load Expectation) event in 10 years. LOLE is defined as the expected number of Loss of Load Events, measuring frequency of outages, but not duration or magnitude. Energy Division welcomes comments on incorporating additional metrics into reliability, such as Loss of Load Hours (which represents the expected total duration of LOLE events but not frequency or magnitude). In particular, how should reliability be measured in off-peak Peak Winter months, when it is not the peak time for electric demand and generation?

Changes to Operating Characteristics of the 17 Gas-Fired Power Plants

Energy Division already has the normal operating characteristics of these power plants derived from the key datasets summarized in the Unified I/A document. Any changes to their operating abilities as a result of reducing or eliminating Aliso inventory should be developed. These include changes to ramping ability and start-up characteristics.

Questions

1. Are the inputs described above appropriate for use in the model as described?
2. Is the proposed time horizon appropriate?

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[12] The Section 715 Reports are formally titled "Aliso Canyon Working Gas Inventory, Production Capacity, Injection Capacity, and Well Availability for Reliability " and can be found at this link: http://www.cpuc.ca.gov/General.aspx?id=6442457392

3. Are LOLE and total production costs good measures of reliability and cost respectively?
4. Are increased startup times and startup profiles and decreased ramp rates the best way to simulate the effect on flexibility in dispatch from electric generation resulting from the more distant gas delivery when Aliso Canyon is unavailable?
5. What is the best methodology to translate hourly electric generation over a year into the 1 in 10 and 1 in 35 design standard gas demand levels needed for hydraulic modeling? Is probability weighted hourly average for weekdays in the month the appropriate method?
6. Are there any other questions that should be considered?

Economic Modeling

The proposed economic study consists of four statistical and/or econometric models that will use historical data to analyze, estimate, and predict the relationships of the gas system to rate impacts for core and non-core gas customers. This includes analyzing the causes and impacts of natural gas price volatility and estimating factors that motivate natural gas storage decisions in the SoCalGas system, (such as weather and natural gas prices). A primary goal is to estimate the impacts of reduction in Aliso gas storage on core natural gas ratepayers in the near term (2019), the medium term (2024) and the long term (2029).

The four analyses are listed here and described briefly below, then further expanded upon in Attachment A.

- Part 1 (Volatility Analysis) will forecast the impacts of volatility on natural gas customer bills in the near term, medium term, and long term, as defined above.
- Part 2 (Factors that Motivate Natural Gas Storage Decisions in SoCalGas) will build on Part 1 to estimate the factors that motivate gas storage decisions on the SoCalGas system.
- Part 3 (The Impact of Natural Gas Storage on Ratepayers' Bills) will quantify and compare the impacts of gas storage availability on ratepayer costs for customers in similarly situated geographic areas..
- Part 4 (The Impact of Tighter Gas Supply in SoCalGas System on Power Generation in the CAISO Territory) will assess the effect of storage availability on customers of electric generation by analyzing the impacts of gas curtailment on hourly energy prices and implied market heat rate.

Part 1: Volatility Analysis

In addition to improving reliability, storage is used to reduce the economic impact of fluctuations in natural gas prices. Gas can be purchased and stored in the off-season, when prices are generally lower, for use in the summer and winter, when demand and prices tend to be higher. Storage also helps moderate costs during temporary price spikes, which typically occur during extreme weather events.

Loss of storage impacts core and noncore customers differently. SoCalGas purchases both gas and storage rights for core customers while noncore customers buy their own gas and have the option to pay for storage rights[13]. Since gas is a pass-through cost for core customers, meaning the price paid by the utility is passed on to residential and small business consumers, loss of storage could increase core customers' exposure to market volatility. Noncore customers have been unable to purchase new storage rights in the primary storage market since restrictions on the use of Aliso were put in place. If Aliso is permanently closed, their ability to purchase storage would likely be severely reduced compared to historic norms, leaving them more exposed to market volatility.

Since SoCalGas core and noncore customers are price takers, it is assumed that the value of SoCalGas storage will be reflected in the SoCalGas Citygate price. Therefore, Energy Division will perform a volatility analysis on both daily and monthly prices of gas purchased at the SoCalGas Citygate hub and compare that volatility to volatility of daily and monthly gas prices in other relevant markets. Energy Division will evaluate volatilities of natural gas prices at hubs including SoCalGas Citygate, SoCalGas border, PG&E Citygate, Henry Hub, El Paso San Juan Basin, and El Paso Permian Basin by using Platts' natural gas market price historical data.

Volatility is typically quantified as the standard deviation of price returns[14]. The return on price is commonly determined in continuous time and expressed using a natural algorithm function of the natural gas price. Once the volatility is computed, if more variation is observed in the SoCalGas Citygate price compared to other markets, Energy Division will perform an **autoregressive model** with explanatory variables to study the relationship between the daily price return of the SoCalGas Citygate natural gas pricing hub and explanatory variables. These variables will include the daily natural gas storage inventories in SoCalGas storage facilities and the reduced capacity of the SoCalGas

[13] https://www.platts.com/commodity/natural-gas

[14] https://ssrn.com/abstract=2194214

pipeline system, due to pipeline outages. In addition, Energy Division will evaluate whether the **Generalized AutoRegressive Conditional Heteroskedasticity (GARCH)[15] model** will be appropriate to this analysis, assuming the data satisfy the model assumptions. These models are especially useful when the goal of the study is to analyze and forecast volatility. These models are commonly used in modeling financial time series that exhibit time-varying volatility.

Part 2: Factors that Motivate Natural Gas Storage Decisions in SoCalGas

ED will analyze the factors influencing SoCalGas' natural gas storage decisions using a linear time series model. In particular, Energy Division is regressing daily net injection volume in SoCalGas gas storage facilities on explanatory variables, such as weather and price, to determine if any of these variables provide a statistically significant predictor of injection volume. To evaluate if this set of explanatory variables influences the storage decision, Energy Division proposes the **AutoRegressive Integrated Moving Average** with explanatory variable (**ARIMAX**)[16] **model**. The ARIMAX model is often used in similar situations because of its ability to eliminate time correlation, which occurs when two time series appear to be correlated only because they are both trending over time.

The initial set of the explanatory variables includes heating degree days (defined as average temperature in the SoCalGas system minus 65°F), cooling degree days (defined as 65°F minus average temperature in the SoCalGas system), SoCalGas Citygate natural gas prices, lagged SoCalGas Citygate natural gas prices, lagged net natural gas injection, day-of-week, occurrence of operational flow order, daily average pipeline available capacity, daily average future price, daily average SoCalGas border spot price, lagged daily average SoCalGas border spot price, dummy variables for the day of the week, and daily average storage inventory level.

Part 3: The Impact of Natural Gas Storage on Ratepayers' Bills

To quantify the effect of storage availability on ratepayers, Energy Division proposes an econometrics technique called "Difference in Differences" (DID). In the DID model, outcomes are observed for two groups during two time periods. One of the groups (treatment group) is exposed to treatment in the second period but not in the first period. The other group (control group) is not exposed during either period[17]. The DID approach can be applied to repeated cross sections of a group or panel data over a time

[15] https://en.wikipedia.org/wiki/Autoregressive_conditional_heteroskedasticity

[16] https://www.mathworks.com/help/econ/arima-model-including-exogenous-regressors.html

[17] http://itp.wceruw.org/documents/Hillmanreading3dimick_ryan_2014.pdf

period. The key assumption in DID is the parallel trend assumption, which states that the average change in the treatment group represents the counterfactual change in the treatment group if there were no treatment.

ED will use monthly billing data from SoCalGas (treatment group) and PG&E (control group) customers whose households have similar characteristics (same zip code, weather, household size, income, etc.) before and after the Aliso Canyon leak and subsequent curtailment. Energy Division will study monthly customer costs for customers in SoCalGas and PG&E service areas in the same zip code including communities in Arvin, Bakersfield, Fellows, Fresno, Del Ray, Fowler, Paso Robles, Selma, Taft, Tehachapi, and Templeton[18]. Outcomes before and after the Aliso Canyon leak will be compared between the test group and the control group. This will allow Energy Division to estimate the effect of curtailment of the Aliso Canyon natural gas storage facility on the monthly natural gas bills of ratepayers.

If the difference in ratepayer cost before and after the Aliso Canyon leak for SoCalGas customers is equal to the difference in ratepayer cost before and after the Aliso Canyon leak for PG&E customers, then the DID estimate is zero and not statistically significant, which means that there is no relationship between low levels of Aliso Canyon storage and the investigated outcome. On the contrary, if there is a relationship between the storage and investigated outcomes, then the DID estimate will be statistically significant.

In addition to the DID analysis above, Energy Division will perform statistical analysis of the underlying billing data to compare bill impacts individually for SoCalGas CARE households and non-CARE households during the summer and winter before and after the Aliso Canyon incident. This statistical analysis will be performed on historical bill data and will include the mean and standard deviation of baseline price, average price, marginal price, gas consumption and total bill, with the overall goal of determining a relationship between Aliso Canyon inventory levels to billing rates.

Part 4: The Impact of Tighter Gas Supply in SoCalGas System on Power Generation in the CAISO Territory

The Aliso Canyon facility provides gas supplies to natural gas-fired power plants that play a central role in meeting regional electrical demand and help them meet peak

[18] https://ei.haas.berkeley.edu/research/papers/WP287.pdf

electrical demands during the summer months. Constrained gas supply from Aliso Canyon can lead to a decrease in availability of natural gas in Southern California, which will lead to dispatch of power plants outside of Southern California. The increased dispatch and flow of electricity into Southern California may raise electricity prices either through dispatching less fuel-efficient plants, or by creating congestion on the electricity transmission system that creates congestion costs. Arguably, these dynamics could mean higher energy costs in the CAISO markets because of the congestion on the transmission network.

Congestion occurs when available, least-cost energy cannot be delivered to some loads because transmission facilities do not have sufficient capacity to deliver the energy. When the least-cost, available energy cannot be delivered to load in a transmission-constrained area, higher cost electricity generation in the constrained area must be dispatched to meet that load. The result is the price of energy in the constrained area will be higher than in the unconstrained area because of the combination of transmission limitations and the costs of local generation.

ED proposes two criteria to assess the impact of tighter gas supply on the power generation in the CAISO's territory; these are the implied heat rate, and the congestion rent assessment, which are discussed briefly hereunder.

Implied Heat Rate

Heat rate refers to the power plant efficiency in converting fuel to electricity. Heat rate is expressed as the number of million British thermal units (MMBtu) required to produce a megawatt hour (MWh) of electricity. Lower heat rates are associated with more efficient power generating plants. Implied heat rate could be obtained by dividing electric price by the natural gas price. Implied heat rate is the break-even natural gas market heat rate assumed because only a natural gas generator with an operating heat rate below the implied heat rate value can make money by burning natural gas to generate electricity. Natural gas plants with a higher operating heat rate cannot make money at the prevailing electricity and natural gas prices[19]. Energy Division will calculate the implied market heat rate for Northern and Southern California parts of CAISO using North of Path 15 (NP15) and South of Path 15 (SP15) day-ahead market electricity prices (MWh), generation data based on the transmission access charge area, PG&E Citygate gas price, and SoCalGas Citygate gas price. In addition, Energy Division will conduct implied

[19] https://www.eia.gov/tools/glossary/index.php?id=I

market heat rate analysis by load level for years 2015, 2016 and 2017 for both Northern and Southern California.

Congestion Rent Assessment

ED will assess the congestion cost related to generation. Energy Division will calculate monthly congestion rent revenue from generation using the marginal congestion component (MCC) of the locational marginal price (LMP) for the day-ahead electric market and the day-ahead market scheduled generation from 2015 through early 2018. The congestion rent will be calculated for Northern and Southern California separately with data obtained from the Open Access Same-time Information System (OASIS).

In addition, Energy Division will provide the monthly frequency of congested hours in the Northern and Southern California, the monthly average electricity price in Northern and Southern California. Furthermore, Energy Division will provide correlation analysis between the daily natural gas price difference (SoCalGas Citygate price minus PG&E Citygate price) and the daily congestion rent revenue from the power generation in Southern California.

Data sources

To perform the econometric analysis, data will be collected from various sources. Most of the data will be requested from SoCalGas and PG&E, while other data will be collected from Platts[20], Envoy[21], and the Energy Information Administration (EIA)[22].

ED will use several datasets such as daily storage inventory level by storage field in SoCalGas system, daily cooling and heating degree days, daily and monthly gas prices for: SoCalGas Citygate, PG&E Citygate, SoCalGas border and Henry Hub, daily pipeline outages, daily operational flow order, daily pipeline available capacity, future natural gas price and daily residential natural gas bill data.

Questions

1. Are the proposed modeling dates reasonable?
2. Are the proposed Aliso inventory levels appropriate?
3. Is it reasonable to model low, mid, and high forecasts of natural gas prices?

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[20] https://www.platts.com/

[21] https://envoy.sempra.com

[22] https://www.eia.gov/

4. Is there an existing gas price forecast dataset that would be appropriate to use in this model?
5. Are there any other inputs or assumptions that should be considered?
6. Are there any other questions that should be considered?

Attachment A: Proposed Economics Modeling:

Energy Division's proposed plan consists of four parts: volatility analysis, factors that motivate natural gas storage decisions in SoCalGas (such as weather and natural gas prices), the impact of natural gas storage on ratepayers, and the impact of tighter gas supply in the SoCalGas system on energy costs for power generation in the CAISO territory. The four analyses are described briefly hereunder.

The economic model is intended to forecast the likely impact a reduction in storage would have on natural gas commodity prices for both core and noncore customers at the SoCalGas border and the SoCalGas city-gate. Historical data will be analyzed and used to create models that will forecast the economic impact in the near term (2019), medium term (2024), and long term (2029).

Volatility Analysis

In addition to improving reliability, storage is used to reduce the economic impact of fluctuations in natural gas prices. Gas can be purchased and stored in the off-season, when prices are generally lower, for use in the summer and winter, when demand and prices tend to be higher. Storage also helps moderate costs during temporary price spikes, which typically occur during extreme weather events.

Loss of storage impacts core and noncore customers differently. SoCalGas purchases both gas and storage rights for core customers while noncore customers buy their own gas and have the option to pay for storage rights[23]. Since gas is a pass-through cost for core customers - meaning the price paid by the utility is passed on to residential and small business consumers - loss of storage could increase core customers' exposure to market volatility. Noncore customers have been unable to purchase new storage rights in the primary storage market since restrictions on the use of Aliso were put in place. If Aliso is permanently closed, their ability to purchase storage would likely be severely reduced compared to historic norms, leaving them more exposed to market volatility.

Since SoCalGas core and noncore customers are price takers, we assume the value of SoCalGas storage will be reflected in the SoCalGas Citygate price therefore Energy Division will perform a volatility analysis on both daily and monthly prices of SoCalGas Citygate and compare it to a similar volatility analysis for other relevant markets.

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[23] https://www.platts.com/commodity/natural-gas

Energy Division will evaluate volatilities of SoCalGas Citygate, SoCalGas border, PG&E Citygate, Henry Hub, El Paso San Juan Basin and El Paso Permian Basin by using Platts' natural gas market historical data.

Volatility is typically quantified as the standard deviation of price returns[24]. In some instances, volatility is defined as the variance of price returns. For the computation of volatility, the return on price is commonly determined in continuous time t, where t is expressed in day or month.
The standard definition of the price return in one period *r(t, t-1)* is calculated as:

r(t, t-1) =ln (p(t)/p(t-1))

Where *p(t)* is the price of natural gas at time *t* and *ln* is the natural logarithm function. If more variation is observed in the SoCalGas Citygate compared to other markets after computing the volatility using the standard deviation of the price returns. The Energy Division will perform an **Autoregressive model** with explanatory variables to study the relationship between the daily price return of SoCalGas Citygate natural gas pricing hub and explanatory variables including daily natural gas storage inventories in SoCalGas storage facilities and the reduced capacity of the pipeline system, due to pipeline outages. Energy Division staff will also evaluate whether the GARCH[25] model will be appropriate to this analysis, assuming the data satisfy the model assumptions.
The initial **Autoregressive** model will take the structure below:

$$\boldsymbol{R_t = C + \sum_{i=1}^{p} \varphi_i R_{t-1} + \sum_{k=1}^{r} \beta_k X_t + \varepsilon_t}$$

- *C* is the constant term (the intercept).
- *Rt* is the price returns at time *t* (dependent variable).
- $\sum_{i=1}^{p} \varphi i Rt\text{-}i$: $Rt\text{-}i$ is the lag of price return (the price return from the previous period or periods) and φ is the coefficient or coefficients to be estimated.
- $\sum_{k=1}^{r} \beta k Xt$**:** Xt is a set of the explanatory variables including the lags of the explanatory variables and β is the coefficient or coefficients of interest to be estimated. This set will include the natural gas storage inventory, pipeline

[24] https://ssrn.com/abstract=2194214

[25] https://en.wikipedia.org/wiki/Autoregressive_conditional_heteroskedasticity

outages, and possibly other variables such as the weather and dummy variables for the day of the week.

- εt is the stochastic disturbance.

The table below shows the variables and data source: 2015-2018

Variable	Data Source
Daily storage inventory level by storage field in SoCalGas system	Data request (DR)
Daily cooling and heating degree days	DR
Daily and monthly gas prices for: SoCalGas Citygate, PG&E Citygate, SoCalGas border and Henry Hub	Platts
Daily pipeline outages curtailment volume in SoCalGas system	DR and Envoy[26]

Factors that motivate natural gas storage decisions in SoCalGas:
In this section, Energy Division will analyze the factors influencing SoCalGas' natural gas storage decisions using econometric analysis, mainly a linear time series model. In particular, Energy Division is regressing daily net injection volume in SocalGas gas storage facilities on explanatory variables including weather, price, or other factors to determine if any of those factors provide a statistically significant predictor of injection volume. To evaluate if this set of explanatory variables has an effect on the storage decision, Energy Division proposes **Autoregressive Integrated Moving Average** with Explanatory Variable (**ARIMAX**)[27] **Model** to study these relationships. The ARIMAX model is often used in situations such as this because in many cases, two time series appear to be correlated only because they are both trending over time. Applying ARIMAX will eliminate the time correlation. .

The initial ARIMAX model will take the following structure:

$$\boldsymbol{Yt = C + \sum_{i=1}^{p} \varphi iYt\text{-}i + \sum_{k=1}^{r} \beta kXt + \sum_{j=1}^{q} \theta \varepsilon t\text{-}j + \varepsilon t}$$

[26] https://envoy.sempra.com

[27] https://www.mathworks.com/help/econ/arima-model-including-exogenous-regressors.html

- Yt is the net injection (dependent variable).
- C is the constant term (the y intercept).
- εt is the stochastic disturbance.
- $\sum_{i=1}^{p} \varphi i Yt\text{-}i$: $Yt\text{-}i$ is the lag of net injection (the net injection from the previous period or periods) and φ is the coefficient or coefficients to be estimated.
- $\sum_{k=1}^{r} \beta k Xt$**:** Xt is a set of the explanatory variables including the lags of the explanatory variables and β is the coefficient or coefficients to be estimated. The initial set of the explanatory variables includes heating degree days (average temperature in the SoCalGas system minus 65 degrees Fahrenheit), cooling degree days (65 degrees' Fahrenheit minus average temperature in the SoCalGas system), SoCalGas Citygate prices, lagged SoCalGas Citygate prices, lagged net injection, day-of-week, operational flow order, pipeline available capacity, future price, SoCalGas border spot price, lagged SoCalGas border spot price, dummy variables for the day of the week and storage inventory level.
- $\sum_{j=1}^{q} \theta \varepsilon t\text{-}j$ **:** θ is the moving average (MA) coefficient and $\varepsilon t\text{-}j$ is the lag of the stochastic disturbance (εt).

The coefficient of interest is the beta coefficient *βk.* For simplicity, assume we have only one explanatory variable called gas price. The question to be answered is, *does gas price have a significant impact on the net injection volume, which can be expressed as*:

Null hypothesis: H0: *βk =0* or that gas price has no impact on the volume of net injection.

Alternative hypothesis: H1: *βk ≠ 0* where *β*k is the coefficient of the gas price variable in the ARIMAX model.

The table below shows the variables and data source: 2015-2018

Variable	**Data Source**
Storage inventory level	DR
Heating degree days	DR
Cooling degree days	DR
Operational flow order	DR and Envoy
Future price	EIA and DR
SoCal border spot price	Platts
SoCalGas Citygate price	Platts
Pipeline available capacity	DR and Envoy

The impact of storage on ratepayers

To quantify the effect of storage availability on ratepayers, Energy Division proposes an econometrics technique called "Difference in Differences" (DID). In the DID model, outcomes are observed for two groups for two time periods. One of the groups is exposed to a treatment in the second period but not in the first period. The second group is not exposed to the treatment (control group) during either period[28]. The DID approach can apply to repeated cross sections of a group or panel data over a time period. The key assumption here is what is known as the parallel trend assumption, which represents the assumption that the average change in the comparison group represents the counterfactual change in the treatment group if there were no treatment.

Energy Division staff will use monthly bill data for SoCalGas (treatment group) and PG&E (control group) customers by household with similar zip codes representing similar areas (similar in weather, household size, income, etc.) before and after the Aliso Canyon leak required curtailment of the Aliso Canyon storage facility. Energy Division staff will study customer prices for customers in SoCalGas and PG&E service areas in the same zip code including communities in Arvin, Bakersfield, Fellows, Fresno, Del Ray, Fowler, Paso Robles, Selma, Taft, Tehachapi, and Templeton[29].

Outcomes before and after the Aliso Canyon leak will be compared between the study group and the comparison group without the exposure (group A i.e. PG&E customers) and the study group with the exposure (group B i.e. SoCalGas customers). This will allow Energy Division staff to estimate the effect of curtailment of the Aliso Canyon natural gas storage facility on the monthly natural gas bills of ratepayers in areas close to each other but differing by their exposure to curtailment of natural gas storage.

Two differences in outcomes are important:1) the difference in bills monthly prices per therm after vs before the Aliso Canyon leak for the SoCalGas customers is (B2 −B1) and 2) the difference in ratepayer cost after vs before the Aliso Canyon leak for the PG&E customers is (A2 −A1). The change in outcomes that are related to the Aliso Canyon incident can then be estimated from the DID analysis as follows: (B2 −B1) −(A2 −A1). If there is no relationship between the storage and subsequent outcomes, then the DID estimate is equal to 0 and not statistically significant. If there is a relationship between

[28] http://itp.wceruw.org/documents/Hillmanreading3dimick_ryan_2014.pdf

[29] https://ei.haas.berkeley.edu/research/papers/WP287.pdf

the storage and subsequent outcomes, then the DID estimate will be statistically significant.

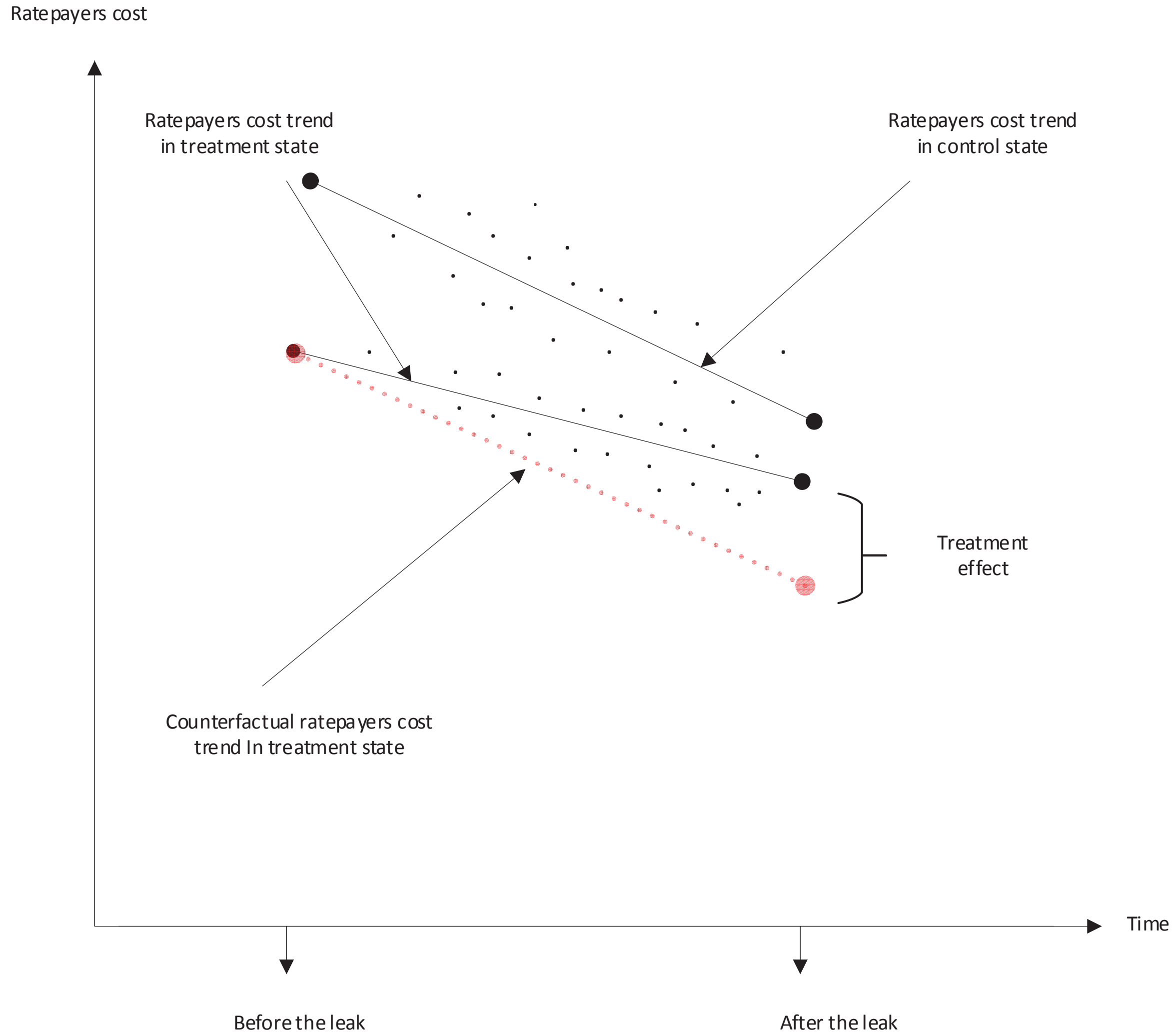
These estimates will be derived from a regression model[30]:

$$Yst = \beta 0 + \beta 1Ts + \beta 2PTt + \beta 3(Ts \times PTt) + \sum_{k=4}^{r} \beta kX + \varepsilon st$$

- *Yst* the observed outcome in group s and period t. In this case, it is the individual ratepayer's monthly bill cost.
- *Ts* is a dummy variable set to 1 if the observation is from the "treatment" group in either time period.
- *PTt* is a dummy variable set to 1 if the observation is from the post treatment period in either group.
- εst is an error term, *β0* is the intercept, *β1* is the coefficient of the *Ts* and *β2* is the coefficient of *PTt*.
- *β3* is coefficient of the treatment effect which is the coefficient of interest. And, the estimate of *β3* is identical to the double difference: (B2 −B1) −(A2 −A1).
- $\sum_{k=4}^{r} \beta kX$**:** X is a set of the explanatory variables and βks are the coefficients to be estimated. This set of the explanatory variables could include variable for low income households, storage inventory levels and pipeline capacity but data need to be evaluated first.

  The graph below illustrates the basic setting of the DID. The hypothesis is that the control group and the treatment group would follow the same cost trajectory with respect to time before and after the curtailment of the Aliso Canyon storage field due to leak.

[30] http://www.nber.org/WNE/lect_10_diffindiffs.pdf



Causal effects in the differences-in-differences model

In addition to the DID analysis above, Energy Division will perform statistical analysis of the underlying billing data to compare bill impacts individually for SoCalGas care households and non-care households during the summer and winter before and after the Aliso Canyon incident. This statistical analysis will be performed on historical bill data and will include the mean and standard deviation of baseline price, average price, marginal price, gas consumption and total bill.

The table below shows the data source:

Variable	Data Source
Bill data	DR from SoCalGas and PG&E
Storage inventory level	DR from SoCalGas
Low income households	DR from SoCalGas and PG&E
Pipeline available capacity	DR from SoCalGas

The impact of tighter gas supply in SoCalGas system on the power generation in the CAISO's territory

The Aliso Canyon facility provides gas supplies to natural gas-fired power plants that play a central role in meeting regional electrical demand and help them meet peak electrical demands during the summer months. Constrained gas supply from Aliso Canyon, can lead to an increase in the natural gas price in Southern California. The price could make gas-based generation more expensive in the south with respect to the north and shift generation from the SoCal system to Northern California. Arguably, these dynamics could mean higher energy costs in the California ISO markets because of the congestion on the transmission network.

Congestion occurs when available, least-cost energy cannot be delivered to some loads because transmission facilities do not have sufficient capacity to deliver the energy. When the least-cost, available energy cannot be delivered to load in a transmission-constrained area, higher cost units in the constrained area must be dispatched to meet that load. The result is the price of energy in the constrained area will be higher than in the unconstrained area because of the combination of transmission limitations and the costs of local generation. But, many factors including the level of demand for electricity and difference in temperature across CAISO's territory can influence the energy prices. Energy Divisions proposes two sets of analysis to assess the impact of tighter gas supply on the power generation in the CAISO's territory: 1) implied heat rate and 2) congestion rent assessment.

Implied Heat Rate:

Heat rate refers to the power plant efficiency in converting fuel to electricity. Heat rate is expressed as the number of thousand British thermal units (MBtu) required to convert a megawatt hour (MWh) of electricity. Lower heat rates are associated with more efficient power generating plants. Implied heat rate could be obtained by dividing electric price by the natural gas price. Implied heat rate is the break-even natural gas market heat rate because only a natural gas generator with an operating heat rate below the implied heat rate value can make money by burning natural gas to generate power. Natural gas plants with a higher operating heat rate cannot make money at the prevailing electricity and natural gas prices. Energy Division will calculate the implied heat rate for Northern and Southern California using North of Path 15 (NP15) and South of Path 15 (SP15) day-ahead market electric price, generation data based on the transmission access charge area; and PG&E Citygate and SoCalGas Citygate for natural gas prices.

The implied heat rate is calculated as shown below. The day-ahead electric price and generation data will be collected from the California **ISO Open Access Same**-time Information System (**OASIS**) site. The daily natural gas data will be collected from Platts. We will use data form 2015 to early 2018.

For Northern California:

$$\boldsymbol{Implied\ Heat\ Ratet} = \frac{\boldsymbol{DALMPt}}{\boldsymbol{DNGPt}}$$

$Implied\ Heat\ Ratet$ is the daily implied heat rate in Northern California.
$DNGPt$ is the daily gas price for PG&E Citygate.
$DALMPt$ is the daily day-ahead weighted average price= $\frac{\sum_h^H \boldsymbol{LMPh*GENh}}{\sum_h^H \boldsymbol{GENh}}$
$LMPh$ is the hourly locational marginal price for NP15.
$GENh$ is the hourly generation for the Northern transmission access charge (TAC) area. It is represented as TAC_NORTH in OASIS.
$\sum_h^H GENh$ is the total generation for all 24 hours in a given day for the TAC_NORTH area.

For Southern California:

$$\boldsymbol{Implied\ Heat\ Ratet} = \frac{\boldsymbol{DALMPt}}{\boldsymbol{DNGPt}}$$

$Implied\ Heat\ Ratet$ is the daily implied heat rate in Southern California.
$DNGPt$ is the daily gas price for SoCalGas Citygate.
$DALMPt$ is the daily day-ahead weighted average price= $\frac{\sum_h^H \boldsymbol{LMPh*GENh}}{\sum_h^H \boldsymbol{GENh}}$
$LMPh$ is the hourly locational marginal price for SP15.
$GENh$ is the hourly generation for the Southern transmission access charge (TAC) area. It is represented as TAC_ECNTR and TAC_SOUTH in OASIS.
$\sum_h^H GENh$ is the total generation for all 24 hours in a given day for the TAC_ECNTR and TAC_SOUTH area combined.

Also, Energy Division will provide implied heat rate analysis by load level for year 2015, 2016 and 2017 for both Northern and Southern California.

Congestion Rent Assessment:
Energy Division will assess the congestion cost related to generation. Energy Division will calculate monthly congestion rent revenue from generation using marginal congestion component (MCC) of the locational marginal price (LMP) for the day-ahead electric market and the day-ahead market scheduled generation from 2015 to early 2018. The congestion rent will be calculated for Northern and Southern California separately. NP15 MCC and TAC_NORTH secluded generation will be used for the Northern California calculation. SP15 MCC and both TAC_ECNTR and TAC_SOUTH secluded generation will be used for the Southern California calculation. Data are available on OASIS.

$$\boldsymbol{CRRG = \sum_{d}^{D} \sum_{h}^{H} MCCh * GENh}$$

CRRG is the congestion rent revenue from generation for a given month in a given year.
$MCCh$ is the MCC for a given hour.
$GENh$ is the scheduled generation for a given hour.
D is the number of days in a given month in a given year and d represent a given day.

In addition to CRRG, energy Division will provide the monthly frequency of congested hours in the Northern and Southern California, the monthly average electricity price in Northern and Southern California.

Finally, Energy Division will provide correlation analysis between the daily natural gas price difference (SoCalGas Citygate – PG&E Citygate) and the daily congestion rent revenue from the power generation in Southern California.

[End of Attachment A]