ATTACHMENT 1:
updated APPENDIX B to January 4th ruling

I.17-02-002

SCENARIOS FRAMEWORK INVESTIGATION 17-02-002

Prepared by CPUC Energy Division

January 4, 2018

Table of Contents

Introduction

In this document, the California Public Utility Commission's (CPUC or Commission) issues its final Scenarios Framework for conducting the modeling studies needed to inform the Ordering Instituting Investigation (OII) 17-02-002. Pursuant to statutory mandate, the OII will determine the feasibility of minimizing or eliminating use of the Aliso Canyon natural gas storage facility (Aliso) while maintaining energy and electric reliability for the region. To help make this determination, the modeling studies will explore two questions: first, whether Aliso is needed for reliability, and if so, the minimum inventory level required, and second, what the cost impact would be if Aliso is to be closed or operated at a level of inventory lower than historic norms.

This final adopted version of the Scenarios Framework builds on the comments received on the previous three draft versions, all in written form and presented at the August 1, 2017, and July 31, 2018 workshops. The section on hydraulic modeling also draws on the CPUC's consultation with Los Alamos National Laboratory (Los Alamos).

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.[1] 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CPUC subsequently required SoCalGas to leave 15 billion cubic feet (Bcf) of working gas in the facility that could be withdrawn to maintain reliability.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[2] 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.

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[1] https://www.gov.ca.gov/2016/01/06/news19263/

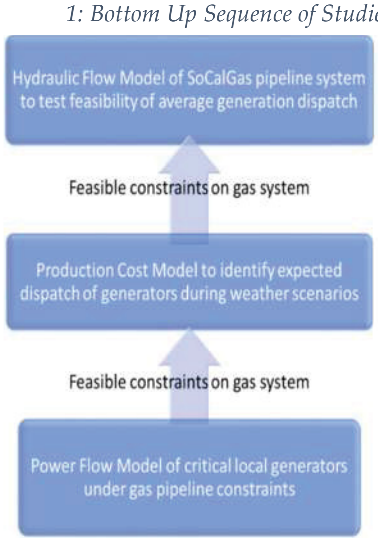
[2] Statues of 2016, chapter 14.

On February 9, 2017, the CPUC opened an OII 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 assumptions 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 to be modeled. Phase 1 will be resolved by the issuance of an Assigned Commissioner's Ruling providing guidance on the assumptions and scenarios that will be evaluated. In Phase 2, the Commission will conduct the analyses agreed to in Phase 1 and evaluate the results; the resulting evaluation 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 operations at pressures between a minimum of 1,080 pounds per square inch absolute (psia) and a maximum of 2,926 pounds psia.[3] These pressures translate into an allowable inventory of working gas that ranges from 0 Bcf to approximately 68.6 Bcf.[4] Any decision about Aliso inventory ultimately reached in I.17-02-002 must fall within the DOGGR-approved range.

Modeling Overview

1: Bottom Up Sequence of Studies



CPUC staff plans to undertake three studies to inform this investigation: (1) hydraulic modeling, (2) production cost modeling (PCM), and (3) economic modeling. In addition, the California Independent System Operator (CAISO) and Los Angeles Department of Water and Power (LADWP) will participate in this investigation by contributing power flow studies of their respective systems to determine local electric reliability requirements that may be

[3]The findings can be found here: http://www.conservation.ca.gov/dog/Documents/Aliso/Enclosure1_2017.7.19_Updated%20Comprehensive%20Safety%20Review%20Findings.pdf

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

impacted by reduction or closure of Aliso. 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.

Bottom Up Sequence of Studies

CPUC staff will evaluate the impacts of Aliso closure or curtailment via a "Bottom Up" approach illustrated in Figure 1. First, the CAISO and LADWP will collaborate with the CPUC on a power flow study meant to identify the minimum local generation in both systems that must be online in order to meet NERC transmission planning and FERC Minimum Local Generation requirements for electric reliability. Second the power flow modeling will be followed by the PCM analysis. Third, the gas demand inputs generated from the PCM and power flow models are input into the hydraulic model.

The power flow model results from the CAISO and LADWP will determine the hourly electricity generation needed to maintain minimum transmission reliability across the SoCalGas system as well as in the Los Angeles basin under a scenario of gas constraints (Minimum Local Generation scenario), which will feed into a PCM analysis in order to determine the likely dispatch patterns of the overall electricity system, while intentionally preserving the Minimum Local Generation in operation.

Hourly profiles of electricity generation will be collected and assembled into input data for the hydraulic model, which will test the feasibility and reliability of those unconstrained system hourly profiles.

CPUC staff will conduct the PCM and economic modeling in-house and has hired Los Alamos to provide oversight and technical assistance of the hydraulic modeling study to be performed by SoCalGas. Los Alamos has overseen hydraulic modeling performed by SoCalGas for previous versions of the Aliso Canyon Technical Assessments.[5] Los Alamos has assisted CPUC staff in updating the hydraulic modeling section of this Framework and will continue to work with the CPUC to provide expertise on the final scenarios to be modeled and assumptions about the gas system. Los Alamos will also

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[5] The Technical Assessments were created by the Aliso Canyon Technical Assessment Group, which consists of the CPUC, the California Energy Commission (CEC), the CAISO, and LADWP, 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/

review the technical interpretation of hydraulic modeling scenarios to be performed by SoCalGas and prepare recommended modifications to SoCalGas modeling.

Hydraulic Modeling: Introduction

In principle, analysis of the coupled electric grid and 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, nor it is -feasible to develop in the time available to complete this investigation[6]. Therefore, CPUC staff constructed a scenario framework 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 use in modeling.

Historically, Aliso has played a key role relative to system reliability and gas prices.

1) Gas system reliability:
    a) When daily or hourly gas demand is higher than the pipeline flowing capacity, gas is withdrawn from storage at Aliso to serve the demand that exceeds the flowing supplies. This functionality is possible because Aliso is close to the major gas demand centers.
    b) When daily gas demand is highly variable, for example when electric generation is re-dispatched in the CAISO hour-ahead or real time market, rapid increases or decreases in the hourly gas demand can cause large pipeline pressure swings. Withdrawals from or injections into Aliso can be used to mitigate these pressure swings and keep the pressure within operating bounds. This is a critical requirement for maintaining safety and avoiding excessively low pressures from limiting gas flows. However, it is possible that nearby underground storage facilities such as Playa Del Rey or Honor Rancho (or other solutions) may be able to substitute for the reliability role that Aliso historically provided or minimize the need to use Aliso.
2) Price Arbitrage:
    a) A 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

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[6] Studies on gas-electric interface are emerging, such as: “The Value of Day-Ahead Coordination of Power and Natural Gas Network Operations” by Pambour, K.A.; Sopgwi, R.T.; Hodge, B.-M.; Brancucci, C. Energies 2018, 11, 1628.

centers while gas prices are low and to release that gas to customers during periods of high prices. This function has declined in importance as increased domestic production of natural gas has led to a decrease in the seasonal variability of gas prices.

Expanding on the gas reliability role above, hydraulics and best practices appear to govern the system operation and reliability more than economics, i.e. if demand exceeds supply, acquiring lower cost or more expensive gas does not obviate the reliability need for withdrawals from underground storage. The same can be said about pressure swings and fluctuations.

For the purposes of this investigation, it appears that economics do not affect much of the hydraulic simulation *near* gas demand centers if the total transmission capacity of each zone is held close to it zonal firm access capacity as provided in schedule G-BTS.[7] Within this investigation, the hydraulic modeling will, for the most part, be independent of the econometric analysis and vice versa. An exception could be made if the need for drastic changes is revealed, such as maximizing the gas flow through uncommon receipts points or gas sources. For such cases, the resulting gas-electric system characteristics may be further analyzed for impacts on the cost of energy services.

For any of the studied months, if the assessment shows that a minimum storage inventory is required at Aliso Canyon, then Aliso Canyon must remain open in the corresponding year under anticipated system configurations. The analysis of the two peak months in the medium- and long-term future years as well as the sensitivity cases will provide an answer to the key question of this analysis, whether Aliso Canyon can be shut down or minimized in those years.

Hydraulic Modeling: Assessment Framework

The hydraulic modeling of the gas system is composed of two assessments – a Reliability Assessment and a Feasibility Assessment. The Reliability Assessment aims to analyze the gas system under peak gas demand conditions on a given day (as previously defined by the reliability standard). The Feasibility Assessment analyzes the gas system under typical demand conditions throughout one year in order to test whether meeting peak demand is “feasible” throughout the typical year, particularly in terms of the required

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[7] The schedule can be found here: https://www.socalgas.com/regulatory/tariffs/tm2/pdf/G-BTS.pdf

minimum withdrawal capacities from underground storage facilities. Figure 2 below is a simple illustration of the hydraulic modeling steps.

Figure 2: Hydraulic Modeling Steps

CPUC staff has determined that the assessment must take a graded approach for the near-term 2020 study year. Specifically, the assessment will be performed every month for the November-March period (winter) and every other month for the April-October period yielding a total of nine simulations for the near term 2020 study year. Gas demand data for the remaining three months could be obtained by interpolation or regression while making use of historical trends.

In addition to these nine simulations, CPUC staff has determined that a sensitivity analysis for the near-term 2020 study year must be included, which will be detailed later. For later study years, specifically 2025 (five years) and 2030 (ten years), the assessment will be performed for the peak winter gas demand conditions and peak summer gas demand conditions only. This is primarily because of the higher uncertainty in the forecasts for the years 2025 and 2030 as well as the uncertainty in the pipeline network condition (repairs, de-ratings or expansions). A description of both assessments follows.

Hydraulic Modeling: The Reliability Assessment

Reliability Assessment: Introduction

The reliability assessment focuses on determining the monthly minimum level of gas in underground storage (i.e. a monthly storage schedule) needed to maintain the reliability of both the electricity and gas systems and to maintain just and reasonable electricity and gas rates.

In this assessment, preference within the model is given to operations of non-Aliso storage facilities as a means to determine the minimum need for gas storage inventory at Aliso Canyon. If the minimum level of inventory is found to be zero for all months, then it will be possible to conclude that closing Aliso would not affect energy system reliability. In the following sections, the reliability standard is introduced followed by a description of the modeling inputs and assumptions and the desired outputs.

Reliability Assessment: The Reliability Standard

The Reliability Assessment determines whether the CPUC's reliability standards can be met during each study month and year.[8] Overall, the natural gas system must maintain the ability to deliver the required gas to each delivery point on the natural gas transmission system (the delivery nodes) at a minimum set pressure without interruption, unless specified otherwise by an adopted gas curtailment protocol (e.g. noncore gas curtailment protocols in Rule 23).

The 1-in-10-year and 1-in-35-year cold winter day standards (also termed *peak* and *extreme peak days* respectively) are derived from Decision (D).02-11-073 and represent demand scenarios to which the SoCalGas and SDG&E gas transmission systems are planned. Each of these standards define two important conditions for the SoCalGas natural gas system:

- The required performance of the natural gas delivery system; and
- The operational actions that are allowable to achieve this performance.[9]

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 rest of SoCalGas's system is acceptable. The Reliability Assessment of the SoCalGas system will use full implementation of all allowable operational actions to achieve the required system performance.

The Reliability Assessment will simulate the performance of the infrastructure system under the conditions of the 1-in-10 peak and 1-in-35 extreme peak day design standards. Design standards are not meant to represent actual historical operating days. In the real world, system operators do not have foresight into upcoming conditions that are available in simulations. The 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 that 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.

[8] See D.02-11-073 and D.06-09-039 for the establishment of reliability standards

[9] All operational actions allowable will abide by CPUC approved rules: https://www.socalgas.com/regulatory/tariffs/tariffs-rules.shtml

These differences between real-world operations and the simulation of the reliability standard may be important to the actual performance of the SoCalGas system and to the cascading stress applied to connected systems. The Reliability Assessment only shows whether it is *possible* to achieve the minimum gas system design standard without implementing operational actions beyond that which is allowable by the standard. Among the operational actions that are allowed within the reliability standards are gas curtailments, which are described next.

The natural gas system is held to two related reliability standards that differ in the level of demand for natural gas and the flexibility that a gas utility has in implementing curtailment of gas demand by certain classes of gas customers (core and noncore, electric gas demand). Within a 1-in-10 peak design day and a 1-in-35 extreme peak design day; the maximum allowable gas demand curtailment is defined for each customer class as follows:

- *Core gas demand*
  No curtailments are allowed for either the 1-in-10 or 1-in-35 standard.
- *Noncore, electric gas demand*
  For the 1-in-10 standard, no curtailment of gas use is allowed for electric generators. This implies that the electric PCM model is unconstrained by gas availability (corresponding to the Unconstrained Gas scenario in the PCM section). For the 1-in-35 design day standard, both non-core electric generation gas demand and non-core non-electric gas demand are completely curtailed if necessary, to alleviate overloading the gas pipeline system.

CPUC staff has evaluated Rule 23[10] gas curtailment protocols to inform our modeling of gas demand curtailments likely on a 1-in-35 day. Rule 23 describes a sequence of curtailments of Dispatched Electric Generation, first attempting curtailment of only 40% of "Dispatched Electric Generation" during the summer months and 60% curtailment in winter months, with the added requirement that all electric curtailments need to be coordinated with the CAISO (Tariff Rule 23, section C.1(2)). If this level of curtailment does not alleviate overloading of the gas transmission system, a more stringent curtailment protocol is effectuated (Tariff Rule 23, section C.1(4)). The gas utility can curtail all electric generators, including "Dispatched Electric Generation" as well as non-

[10] https://www.socalgas.com/regulatory/tariffs/tm2/pdf/23.pdf

electric non-core customers, followed by curtailing core customers, until the overloading conditions are resolved.

In modeling the 1-in-35 extreme peak design day standard, CPUC staff will simulate 1-in-35 gas demand but a modified 1-in-35 standard for electric generation curtailments. Curtailment of electric generation gas demand in the hydraulic flow model will start with Rule 23 section C.1(2)—curtailments of up to 40% to 60% of electric generation depending on the season relative to the Unconstrained Gas Scenario, while preserving those electric generators required to meet the FERC Local Capacity Area Resource Requirements. If that is not adequate to prevent exceeding maximum allowable operating pressure on the gas pipeline system, CPUC staff will then implement curtailment protocols in the hydraulic model from section C.1(4), preserving only the Minimum Local Generation from the power flow model and nothing else. This corresponds to the Minimum Local Generation scenario. Non-core non-electric gas demand will also be completely curtailed consistent with Rule 23 section C.1(3).

The results of the CAISO and LADWP's power flow studies, detailing the minimum local generation requirements to meet FERC Local Capacity Area Resource Requirements will be fed into the PCM model and those generators will be dispatched without constraints in the Minimum Local Generation scenario while other generators will be potentially curtailed. The hourly gas demand produced in simulating the Minimum Local Generation scenario will be used to create the hourly gas demand profiles modeled in the hydraulic model for the 1-in-35 extreme peak day (see Figure 3 and Figure 4).

- *Noncore, non-electric gas demand*
  For the 1-in-10 standard, no curtailments are allowed. For the 1-in-35 standard, full curtailment to zero can occur if needed, while maintaining certain carve outs as specified in Rule 23.

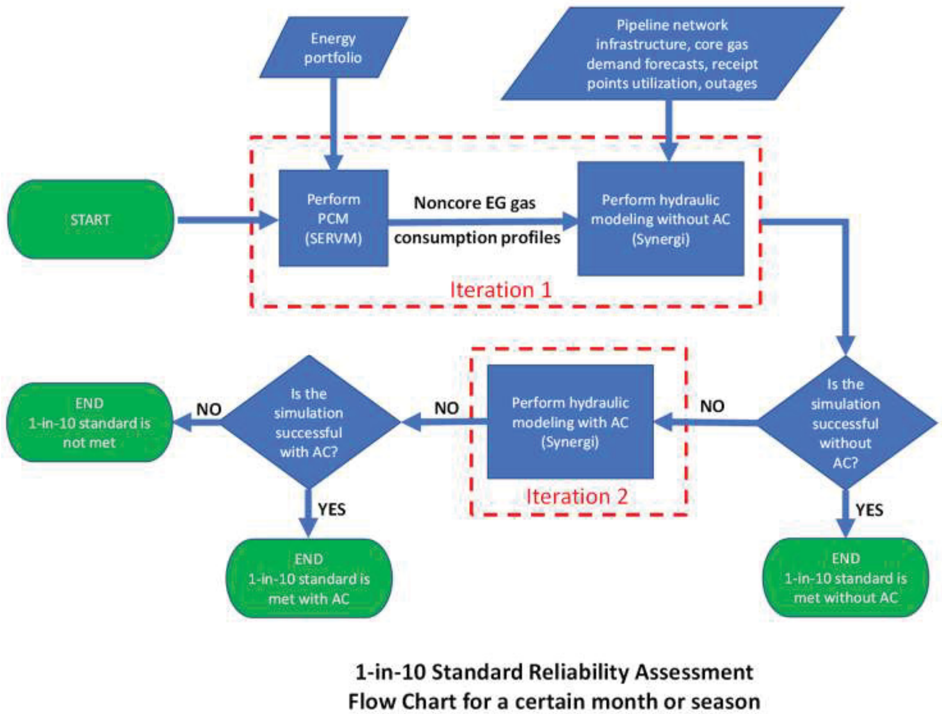

Figure 3: Simplified Flow Chart for Reliability Assessment of the 1-in-10 standard

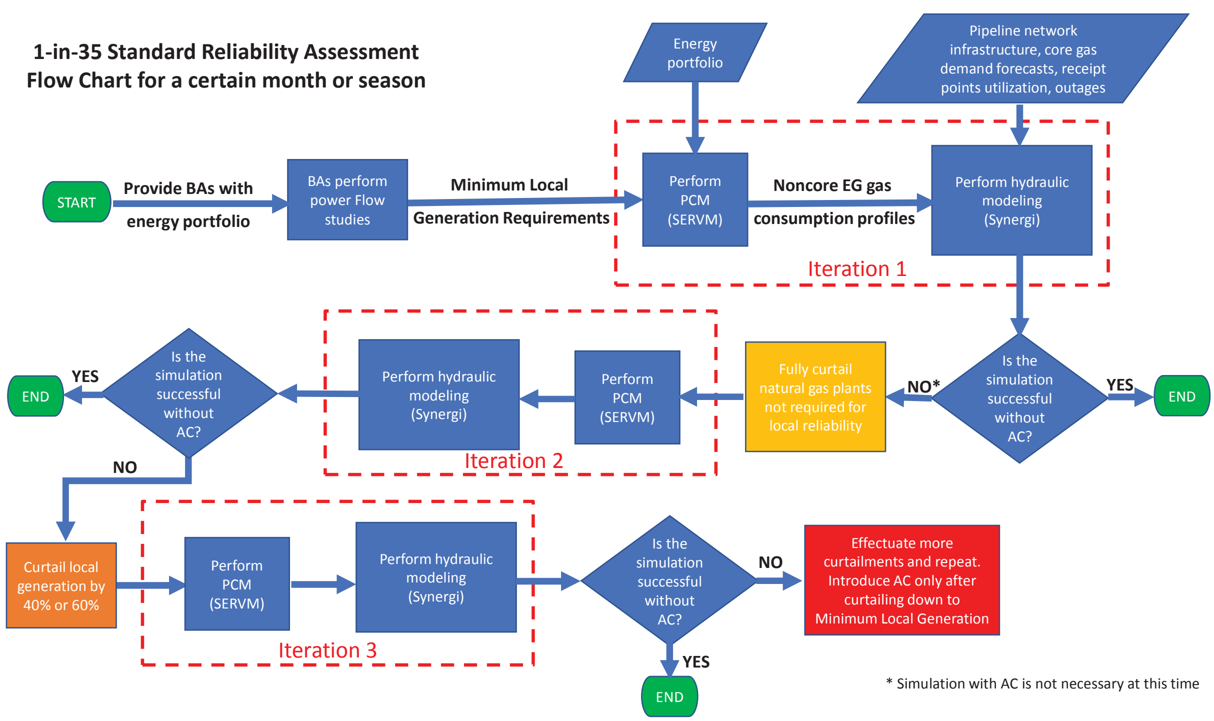

Figure 4: Simplified Flow Chart for Reliability Assessment of the 1-in-35 standard

Reliability Assessment: Steady and Transient Simulations

In order to perform the reliability assessment on the natural gas system, multiple hydraulic simulations must be run for each month individually. First, a steady-state simulation must be run, and a steady-state solution must be established for each monthly case. A steady state simulation is a type of simulation where fluid and flow properties do not vary with time (because demand is assumed constant). Once a successful steady-state solution is established, then a transient simulation can be initialized, during which the flow properties are allowed to vary with time to meet variable gas demand. In other words, the steady-state solution provides the initial condition from which the transient simulation can start, while the transient simulation investigates the performance (pressure and flow) of the natural gas pipeline network under varying gas demand. This process needs to be undertaken for each month individually.

Whether it is a steady-state simulation or a transient simulation, the natural gas pipeline network parameters will be setup in the modeling software Synergi. This includes pipeline properties (e.g. lengths, diameters, locations, friction parameters, etc.), fluid properties (natural gas density, temperature, compressibility, etc.), compressor stations (locations and performance characteristics), and flow control valves and pressure regulators (locations and characteristics). Most of these properties should not vary from one simulation to the next. However, the most important properties that can vary are valve and compressor settings based on the flow configuration (e.g. which receipt points are scheduled to receive gas or whether a certain storage facility is set to inject or withdraw). All this data is stored in a "case file" by the modeling software and will be reported to the CPUC (or its collaborators) and Los Alamos National Lab where it will be reviewed and investigated.

When the pipeline network is fully described, the next step is to prescribe what is to happen at the boundaries of the pipeline network (termed "boundary conditions"). Boundary conditions include the flow at the delivery nodes (demand), the pressure (or flows) at the various receipt points (scheduled receipts), and the valve configuration along the pipelines and at the storage facilities (withdrawing or injecting). These boundary conditions will dictate the required inputs needed to run a hydraulic simulation and these boundary conditions will vary based on which reliability standard is being modeled. Boundary conditions translate to "operational" or "real-life" inputs such as gas demand profiles and gas curtailments, which will be discussed in the next section.

Reliability Assessment: Simulations Inputs

To perform the Reliability Assessment, several inputs are required by the hydraulic simulations, which vary based upon which of the two reliability standards is being modeled. Some of the inputs required in the case file include the natural gas demand profiles, gas curtailment standards, SoCalGas pipeline and compressor station operational characteristics, each gas storage facility's maximum withdrawal and injection 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. These inputs and assumptions are described below.

1. **Hourly gas demand profiles**
   For the natural gas system, hourly gas demand profiles (i.e. gas demand as a function of time over 24 hours with one-hour increments) must be defined for the three types of gas customers for both reliability standards.

   - *Core gas demand*
     Since historical hourly data is not available for peak (1-in-10) or extreme peak (1-in-35) core gas demand conditions for a suitable number of historical years, an approximation must be made, and a "synthetic" gas use profile must be derived. CPUC staff will derive a peak demand hourly profile *shape* from smart meter data obtained from the beginning of 2016 to the present.

     To generate the profile *shape* of gas demand (*not* the peak magnitude), CPUC staff will collect hourly smart meter data for a whole year for each zip code served by the utility company. Then, for each month of the year, the day that corresponds to the highest total daily core gas demand will be selected as a representative shape for both the peak and extreme peak demand design day core use profiles (1-in-10 and 1-in-35).[11]

[11] Staff acknowledges that recent years have not been extreme in temperature, but this approach is needed to derive the profile shape. The 90^{th} percentile represents the chance of a 1-in-10 peak demand.

The hourly gas demand shapes will then be stretched using total daily use and peak hourly use parameters such that the total daily use and peak hourly use are consistent with forecasts from the most recent California Gas Report (CGR). This methodology is similar to what CPUC staff performs for hourly electricity demand shapes, which is explained in the Unified Inputs and Assumptions in section 2.6.3.[12]

Upon analysis of the profiles, the CPUC may keep all 12 profile shapes per zip code (one per month). If profiles are strongly similar for a whole season or across many months, profiles may be merged or dropped, but no less than two hourly profile will be included in the simulation, representing the summer and winter seasons. The most important shape metric is the maximum rate of change of gas demand (mathematically termed maximum slope or gradient), which translates to sudden increases in gas demand, and will therefore affect the performance of the pipeline network.

- *Noncore, electric generation gas demand*
  Hourly noncore, electric generation gas demand profiles to support electric generation will be computed from a PCM that simulates the operation of electric generators to meet gas demand on an hourly basis. There is no need to scale or stretch the resulting gas use profiles to a forecast, given that the results of the PCM model include expected gas demand for electricity generation for the necessary study years. Depending on the reliability standard being modeled, CPUC staff will perform a PCM simulation on one of two scenarios as described below.

  For the peak (1-in-10) day, CPUC staff will perform a PCM simulation of the WECC electric system with no gas supply constraints and determine hourly gas demand profiles based on the economically optimal production of electricity (Unconstrained Gas scenario).

[12] The Unified Inputs and Assumptions document is posted to the CPUC website here: http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/1Unified_IA_main_draft_20180220.pdf

For the extreme peak (1-in-35) day, CPUC staff will perform a PCM simulation of the Western Electric Coordinating Council electric system (which covers the western half of the United States) while curtailing electric generation in CAISO and LADWP which is attached to the SoCalGas system except for the minimum local generation identified as necessary to meet FERC Local Capacity Area Resource Requirements in the power flow model (Minimum Local Generation scenario). Details about the PCM are discussed in the PCM section.

- *Noncore, non-electric gas demand*
  For both reliability standards (1-in-10 and 1-in-35), the gas demand for noncore, non-electric customers will be obtained directly from the CGR.

2. **Gas Storage Facilities**
The natural gas pipeline and storage system is modeled for the peak and extreme peak days, and the required hourly withdrawals from underground storage facilities are determined accordingly. Withdrawals from non-Aliso facilities are utilized first. If non-Aliso facilities cannot support the total demand, then withdrawals from Aliso are used to serve the remaining gas demand that is not allowed to be curtailed in the scenario. Details about the modeling approach for each storage facility is described below.

- *Playa Del Rey (PDR)*
  The PDR storage field has relatively small storage capacity, but it is key to gas control operations and the 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[13] study and in actual gas control operations. PDR has a relatively short refill time (approximately a few days). Therefore, PDR can be considered at maximum storage capacity and can supply the corresponding maximum withdrawal rates on any peak day.[14]
- *La Goleta*

[13] Aliso_Canyon_Risk_Assessment_Technical_Report_Summer_2017_Assessment. May 19, 2017.
[14] If alternative scenarios are considered that span more than one day, the availability of maximum withdrawal rates at PDR comes into question, and this assumption should be revisited.

The La Goleta storage field has access to limited pipeline transportation capacity. On a peak day, pipeline constraints limit the ability of this storage field to support peak gas demands to the south in the Los Angeles Basin. This field is used in more of a "baseload" manner to support the overall recovery of system-wide "linepack."[15] Any peaking storage withdrawal from this field is used primarily to support peak gas demands in the coastal Santa Barbara and Ventura County 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 maximum storage capacity and maximum withdrawal rates on any peak day, gas flows will be 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. In the absence of Aliso Canyon, it is key to supporting peak gas demands in the Los Angeles Basin. However, the full withdrawal capacity of Honor Rancho may not be achievable because it competes with gas receipts from Wheeler Ridge for transportation capacity. If both Honor Rancho storage withdrawal and Wheeler Ridge receipts are maximized, pipeline pressure would exceed the maximum allowable operating pressure, 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 limited by pipeline transportation constraints, and the available aggregate supply from these sources is determined by this limit.
- *Aliso Canyon*
  The Reliability Assessment will compute the required withdrawals from Aliso to maintain reliability and balance in the SoCalGas system. Therefore, no assumptions about this field are required. Since the modeler must manually specify the configuration of valves or whether the storage facility is set to inject or withdraw, the first step will be to assume "closed" valves or "zero" injections and withdrawals. If the

[15] Linepack refers to storing gas in the pipeline as opposed to within a storage facility.

simulation fails with Aliso set to zero, then the required Aliso withdrawal rate will be computed.

3. **Flowing Gas Supplies**
Under the stressed conditions of the Reliability Assessment, it is anticipated that the flowing supplies at the receipt points will be 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. Gas scheduling occurs in advance of gas burn; therefore, gas system operators may need to make real-time adjustments. However, in real-time operations, and due to restrictions on pipelines, outages, or limitations on injection capacities, the total transmission zone firm access (Schedule G-BTS) may not be achievable.

A preliminary analysis of historical gas receipt data[16] on the zonal transmission capacity[17] from January 2014 to August 2018 reveals the following trends:

- In 2014, the Southern Zone had an average transmission capacity of about 60% of its nominal capacity. The average capacity of the Southern Zone increased to about 65% in the 2016-2018 period. During the 2016-2018 period, there was a 9% chance that the zonal transmission capacity would be at or above 85%.
- In 2014, the Northern Zone had an average transmission capacity of roughly 75% of its nominal capacity. The average capacity has been declining, reaching about 50% in the 2017-2018 period. This appears to be due to sustained pipeline outages and restrictions in the Northern Zone. However, for the period from January 2014 to July 2015, there was a 20% chance that the zonal transmission capacity would be at or above 85%. During this same period, the zonal transmission capacity was above 95% for 3% of the days.
- For the 2014-2018 period, the Wheeler Ridge zone had a chance of 76% of operating at or above 85% of its nominal capacity and a 40% chance of operating at full nominal capacity.

[16] Historical gas receipt data can be found on ENVOY: https://scgenvoy.sempra.com/index.html

[17] Nominal zonal capacities used for this analysis are 1.21, 1.59 and 0.765 Bcf/day for the Southern, Northern and Wheeler Ridge zones respectively.

- Staff acknowledges that recent years have not been extreme in temperature. Therefore, this analysis is complemented by the sensitivity analysis discussed in later sections.

Since the reliability standards investigate 1-in-10 and 1-in-35 demand conditions (which correspond to approximately a 10% and a 3% chance), and based on the numbers summarized above, it appears reasonable to use the following assumptions about the zonal capacity for the hydraulic modeling:

- Southern Zone 85% of its capacity during peak and extreme peak days.
- Northern Zone: 85% of its capacity during peak and extreme peak days.
- Wheeler Ridge Zone: 100% of its capacity during peak and extreme peak days.

These historical capacities represent an "average" or a rough estimate of the transmission capacity throughout the system during a representative period. Therefore, these reduced capacities may or may not include the effect of outages in the natural gas network system. These reduced capacities may also be a result of injection limitations, customers' decisions (core and noncore), or real-time operational constraints.

Until a correlation can be established or ruled out between reduced system capacities and unplanned system outages, it cannot be assumed that the pipeline network system is operating at full nominal capacity during a 1-in-10 or a 1-in-35 design day (this is especially true for an aging pipeline system). The opposite is also true; one cannot assume that the reduced capacities will persist on a 1-in-10 or 1-in-35 design day. In addition, in a previous decision by the CPUC, the CPUC has not adopted a mandatory slack capacity requirement.[18]

Therefore, considering the current condition of the SoCalGas pipeline network, it would be prudent to perform a sensitivity analysis on unplanned outages and zonal capacities, as was done in previous technical assessments and the Public Utilities Code Section 715 Reports. CPUC staff will use the information gathered from the outage analysis to inform assumptions regarding capacity utilization levels in the hydraulic modeling. CPUC staff's planned analysis of system outages is discussed in more detail below.

[18] D.02.11.073, page 9

4. **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 gas system modeling. 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, the gas pipeline system will 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 will be carried out using historical records. A related analysis was carried out by SoCalGas and reviewed by the CPUC, the CEC, the CAISO, and LADWP in the April 2016 Aliso Canyon Risk Assessment Technical Report.[19] Table 3 of the report summarizes the calculations carried out to determine the range of estimated days the SoCalGas and SDG&E system will be under significant stress.

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 CPUC will use the approach in the April 2016 Technical Assessment with the following additional guidelines:

- The highest impact unplanned outage should be determined using historical data rather than coming up with hypothetical unplanned outages.
- CPUC staff will define multiple representative periods over which outage data are collected and analyzed, including at least one period prior to the Aliso leak in October 2015, to ascertain the typical level of system outages on the SoCalGas system. Other representative periods could be the past three, five and ten years or one-year intervals for the past 10 years.

[19] 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

- For each unplanned outage, CPUC staff will collect outage date, outage type, outage duration, impact on reduction in pipeline capacity, zonal capacity, and system capacity. In addition, CPUC staff will obtain average system send out during the outage. These outages could be pipeline related (leak, break, explosion, etc.), a compressor unit at a compressor station, or one of the valves or pressure regulators.
- Define probability of an outage as the total duration of an outage divided by the duration of the representative period
- Define lifetime probability of an outage as the total duration of outage divided by the age of the corresponding component
- Analyze both probabilities defined above for impact, correlations and trends.
- Depending on correlations and trends from the previous step, unplanned outages with probabilities less than 10% and 3% for the 1-in-10 and 1-in-35 standards respectively *may be* excluded from the selection pool. This is especially true if these outages do not correlate with stress days.
- Using the analysis results and engineering judgment, select the most likely Aliso and non-Aliso outages during a 1-in-10 and 1-in-35 design days and introduce it in the Reliability Assessment sensitivity matrix.
- Repeat the analysis above for planned outages and calculate utilization factors for injection capacities and zonal capacities, which would be implemented in the feasibility study.

Outages are also related to the transmission zone capacity discussed above, where CPUC staff suggests using 85% of the zonal nominal capacity based on historical data. It is possible that this percentage is tied to historical pipeline outages (rather than injection capacity limitations or low gas demand). More outages would translate to historically lower utilization of the zonal capacity. CPUC staff will investigate the impact of different types of outages on the zonal capacity. CPUC staff may revise the zonal utilization based on findings.

For each study month, the impact of the non-Aliso outage must be analyzed. In addition, if withdrawals from Aliso are needed when a non-Aliso outage is imposed, then the impact of Aliso outages must also be analyzed. This could be summarized as follows:

a) Impose the non-Aliso outage and perform the simulation. If the simulation is successful and no withdrawals from Aliso are required, then the analysis is complete.
b) If the simulation is successful but shows that withdrawals from Aliso are required, then the impact of Aliso outages must be analyzed. This will be done by replacing the unplanned non-Aliso outage with an unplanned Aliso outage, and re-running the simulation, while still giving preference to non-Aliso components first.
c) Select the higher withdrawal rate obtained from both simulations (One withdrawal rate for each imposed outage; Aliso and non-Aliso).

CPUC staff will use the following matrix to assess the reliability of the SoCalGas pipeline network in the near term (2020): every other month during April-October and every month for the rest of 2020 (November-March), bringing the number of simulations for 2020 to 18 (nine for each reliability standard). For years 2025 and 2030, CPUC staff finds that it is sufficient to perform the Reliability Assessment only for the peak winter and peak summer periods. In addition, CPUC staff is expanding the Reliability Assessment simulation matrix to include sensitivity analyses related to zonal capacities and pipeline outages. The matrix for the Reliability Assessment is summarized in Table 1. The graded approach to the hydraulic modeling will result in 26 simulations for the Reliability Assessment. Eight of these scenarios result from performing the Reliability Assessment for two seasons each in 2025 and 2030 under peak and extreme peak conditions. Additionally, 4 more scenarios are reserved to perform sensitivity analysis on zonal utilization and outages.

Table 1: Hydraulic Modeling Scenarios

Case #	**Year Studied**	**Operating Condition Peak (1-in-10) Extreme Peak (1-in-35)**	**Outages U: Unplanned P: Planned**	**Assumed Zonal Capacity (Southern, Northern, Wheeler Ridge)**	**Gas Demand Curtailment**
	Reliability				
Base					
1-9	9 months 2020	Peak	U	85%, 85%, 100%	None
10-18	9 months 2020	Extreme Peak	U	85%, 85%, 100%	Some
19	Summer 2025	Peak	U	85%, 85%, 100%	None

Case #	Year Studied	Operating Condition Peak (1-in-10) Extreme Peak (1-in-35)	Outages U: Unplanned P: Planned	Assumed Zonal Capacity (Southern, Northern, Wheeler Ridge)	Gas Demand Curtailment
20	Summer 2025	Extreme Peak	U	85%, 85%, 100%	Some
21	Winter 2025	Peak	U	85%, 85%, 100%	None
22	Winter 2025	Extreme Peak	U	85%, 85%, 100%	Some
23	Summer 2030	Peak	U	85%, 85%, 100%	None
24	Summer 2030	Extreme Peak	U	85%, 85%, 100%	Some
25	Winter 2030	Peak	U	85%, 85%, 100%	None
26	Winter 2030	Extreme Peak	U	85%, 85%, 100%	Some
	Sensitivity				
27	Winter, 2020	Peak	None	100%, 100%, 100%.	None
28	Winter, 2020	Peak	U	100%, 100%, 100%.	One
29	Winter, as needed	Peak	None	100%, 100%, 100%.	None
30	Winter, as needed	Peak	U	100%, 100%, 100%.	One
	Feasibility				
31-42	Monthly, 2020	Typical	U+P	Outages Analysis	None

Reliability Assessment: Simulations Outputs

The hydraulic simulation outputs are the required hourly withdrawals from non-Aliso and, if needed, Aliso gas storage facilities. The Reliability Assessment gives priority to withdrawals at non-Aliso facilities in order to minimize or eliminate usage of the Aliso facility. A hydraulic simulation is considered successful if:

- The pressure at all demand nodes is held above the minimum required pressure at these demand points for the duration of the simulation.
- All facilities must operate within established capacities (i.e. demand is met).
- The maximum pressure does not exceed the Maximum Allowable Operating Pressure (MAOP) at any point or time.[20]
- "Linepack" is restored, i.e. the amount of gas present in the pipeline at the end of the simulation is approximately equal to the amount of gas at the beginning of the simulation which guarantees each operating day does not impose any constraints on future days.

[20] MAOP is defined and set by 49 CFR 192.

- Storage fields can maintain the required withdrawal (or injection) capacity (mass flow rate).

At each facility except for PDR,[21] hourly withdrawal rates that result from hydraulic modeling are converted into minimum gas inventory using the maximum withdrawal rate curves derived from SoCalGas operation of these facilities[22]

In certain months of the year when the monthly peak day does not stress the gas system to a high degree, 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 minimum withdrawal capacity for each storage facility, discussed above. This does not violate the assumptions of the Reliability Assessment. Instead it provides the relevant data on the required withdrawals.

For each simulated month, either the 1-in-10-year analysis or the 1-in-35-year analysis will result in a higher withdrawal (compared to typical or average demand) from the underground gas storage fields. The higher of the two is used to determine the minimum gas storage requirement or a "gas schedule." By the end of the Reliability Assessment, the analysis will arrive at a "Minimum Gas Storage Schedule" for each simulated month studied (nine months in 2020, peak summer and winter months of 2025 and 2030), at each gas storage facility. The minimum gas storage requirement for non-simulated months (May, July, and September) may be obtained by interpolation or regression and compared to historical data from previous years to verify the accuracy of the interpolation or regression.

For simulations deemed unsuccessful (because one of the criteria listed above was not satisfied), it may be possible to locate a point of failure. CPUC staff anticipates that the failure criterion is most likely a point with an excessive pressure drop (also termed "draft" by the pipeline operator). For this reason, CPUC staff will log and report to stakeholders the flow and fluid properties during the transient simulations at various

[21] 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 unless there are several high-use days in a row.

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

points throughout the system (before and after compressors, regulators, major valves, major junctions, CityGates, and receipts points to name a few).[23] However, it is of outmost importance to note that pinpointing "a" point of failure or bottleneck will *not* rule out the existence of other points of failure in the pipeline network.

Hydraulic Modeling: The Feasibility Assessment

Feasibility Assessment: Introduction

Once the Reliability Assessment is complete, the resulting minimum storage schedule will be assessed for feasibility. Therefore, the next step in the analysis is a Feasibility Assessment. In the Feasibility Assessment, the gas system is simulated under typical demand conditions to determine the available capacity for injection at the SoCalGas storage facilities. The distribution among the different storage fields requires more hydraulic analysis since it depends on the location of those storage fields and the gas system properties.

Feasibility Assessment: The Feasibility Standard

A Feasibility Assessment will be carried out to determine if the monthly minimum storage volume targets determined by the Reliability Assessment can be maintained throughout the study 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" system conditions for each month to assess the typical available gas storage injection capacity and any associated withdrawals that may be required in typical monthly operation. These monthly typical injection or withdrawal capacities are then used to determine if the monthly minimum storage volume targets resulting from the Reliability Assessment 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 typical system conditions and do not significantly impact the total storage volumes over a several-month time frame.

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[23] CPUC staff will make every effort to maintain transparency in this process and share resulting failure or bottleneck points, but will not be able to share confidential information with stakeholders.

Feasibility Assessment: Methodology

There are three approaches to conduct the simulations for the feasibility assessment. The first approach is to conduct a "full transient simulation" in order to simulate varying demand and varying injection throughout a 24-hour simulated day. This approach would simulate the decisions made by the pipeline operator who may choose to inject during off-peak hours, stop injecting during peak hours, or make other operational decisions.

The second approach is to run a "steady state simulation", which assumes constant hourly demand and constant hourly injection (or withdrawal) capacities during a 24-hour simulated day. It is then assumed that the pipeline operator is able to handle the varying demand and still meet the storage volumes calculated by the steady state simulation.

A third approach, termed "mass balance sheet", which has been used by the CPUC before (as in the Public Utilities Code Section 715 reports), is to compute a gas balancing sheet. This is done by looking at historical data and calculating the typical demand and injection capacity during a certain month. In addition, predictions about the zonal capacities must be included (or a sensitivity analysis on zonal capacities).

Ideally, the three approaches should yield similar storage volumes for each month, because all three approaches will average over an entire month while respecting the injection capacities of all underground storage facilities. The "mass balance sheet" approach is intuitive, simpler to follow and requires fewer computational resources although it may fail to capture the local transmission restrictions that must be obeyed by the pipeline operator during a "typical" demand day. This could lead to lower injection (or withdrawal) capacities. These restrictions may exist on one day but not the next day due to varying daily demand.

Therefore, CPUC staff maintains that in order to use the mass balance sheet approach, it must be shown that the pipeline network system bottleneck during a typical demand day is the injection capacity whether Aliso is in service or not. In other words, it must be shown that the amount of additional gas (in excess of demand) can be delivered (transmitted) all the way to the required storage nodes during a 24-hour period. This determination requires a steady state simulation.

In summary, CPUC staff will first conduct two steady state simulations with typical conditions for the May study month, which is historically the month with lowest gas demand. Modeling a low demand month such as May will maximize the additional gas available for injection. CPUC staff will also assume full zonal utilization and model May with and without Aliso availability. The results of this simulation will indicate whether the pipeline system is limited by the injection capacity of the underground storage facilities or limited by local capacity constraints.

If it is shown by the steady state simulations that the pipeline network system under May low core gas demand conditions is limited by the injection capacity only, then a "mass balance approach" is warranted for the whole year. On the contrary, if one of the simulations show that the injection capability of the pipeline network system is limited by other conditions (such as local transmission constraints) under typical low core gas demand, then these conditions must be revealed using a "full transient simulation" as outlined in the next section and these limitations must be incorporated in the mass balance sheets or the steady state simulations.

Feasibility Assessment: Transient Simulations Inputs

As with the Reliability Assessment, the transient hydraulic simulations for the Feasibility Assessment would require several inputs, namely gas demand profiles, gas curtailments, assumptions about storage facilities, assumptions about capacity utilization, and assumptions about the gas network outages. A description of each input follows.

1. **Hourly gas demand profiles**
   For the natural gas system, hourly gas demand profiles are defined for the average operating conditions, i.e., a historical operating day with average total gas use compared to all days in the month of the study year(s). The gas demand profile is determined from its three constituents:
   - *Core gas demand*
     Average daily core gas demand profile for each month of the study year from the most recent CGR.
   - *Noncore, electric generation gas demand*
     Daily gas consumption profiles from a year-long electric PCM are produced from hourly output data from each month of the year to define the average daily noncore, electric generation gas demand profile. The electric PCM will be performed without constraints (Unconstrained Gas

scenario) on gas availability so that the electric generation is committed and dispatched to achieve economically optimal operations.

- *Noncore, non-electric gas demand*
  Average forecasted daily core gas demand profile for each month of the study year from the CGR.

2. **Gas curtailments**
   Since the Feasibility Assessment simulates the gas system throughout a typical year, no curtailments are assumed.

3. **Gas storage facilities**
   The natural gas pipeline and storage system is modeled for a day with average total gas demand 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 relative to load or to provide system balancing. The injection and withdrawal capacities are used to calculate whether the required storage inventories can be achieved over a full month. If the available injection capacity (minus required withdrawals) is sufficient to meet the required gas storage monthly minimums determined in the Reliability Assessment, the Minimum Gas Storage Schedule is deemed feasible. Each of these facilities is unique and operated in a specific manner for the greatest benefit to the gas system as described below.

   - *Non-PDR Gas Storage*
     La Goleta, Honor Rancho and Aliso Canyon (if required by the Reliability Assessment) 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 demands are met without imposing curtailments

and 2) to ensure that all facilities are at least above their required monthly minimums from the Reliability Assessment.

- *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 typical operations during certain months of the analysis year. PDR's small storage capacity means that it cannot be continually drawn down. In the typical 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 typical day. This "typical day balance" condition is used for PDR in the Feasibility Assessment instead of a monthly minimum gas storage target. This implies that PDR can only be used to respond to rapid changes in demand rather than consistent withdrawals. If consistent withdrawals are still required from PDR even after withdrawing from non-PDR facilities (without or with Aliso), then this must be done while maintaining the minimum levels required by the reliability assessment.

4. **Flowing Gas Supplies**
   As in the Reliability Assessment, the total transmission zone capacity will be assumed at 85% for the Northern and Southern Zone and 100% for the Wheeler Ridge Zone. In addition, upon analysis of the unplanned and planned outages as outlined in the Reliability Assessment section, utilization factors of the different zones and components may be updated to account for these outages as well as to account for the maintenance and safety inspections.

5. **Outages**
   In contrast to the Reliability Assessment, the Feasibility Assessment must consider both planned and unplanned pipeline and storage outages. Both types of outages occur under typical 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, each gas pipeline system model (one model per month of the year) will be subject to reductions in flowing supply and reductions in storage operations that are consistent with expectations from the historical record of these outages during that month.

Such an analysis is presented in Table 3 of the 2016 version of the Aliso Canyon Risk Assessment Technical Report, which will be updated for this hydraulic analysis to reflect current data. 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.

There is no apparent need to consider the highest impact pipeline or storage outage since the Feasibility Assessment assumes a typical year with typical demand and, consequently, a typical outage situation. However, it is important to consider the "typical" outages before and after the October 2015 leak. CPUC staff will analyze the impact of outages on capacity utilization before and after October 2015. CPUC staff will then choose a representative period of "typical" outages for the year 2020, 2025 and 2030 to inform the hydraulic modeling of those years.

Feasibility Assessment: Simulation Outputs

The gas storage net injections and net withdrawals from the hydraulic modeling are for a typical 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 is deemed feasible. Two to twelve simulations are needed for the Feasibility Assessment depending on whether mass balance or full transient simulations are required as shown in Table 1.

Hydraulic Modeling: Potential Future Analysis

The Reliability Assessment 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. On the other hand, the Feasibility Assessment determines whether the monthly minimum storage volume targets determined by the Reliability Assessment can be maintained throughout a typical year.

The Reliability Assessment may return a result that does not meet the required natural gas delivery needs, even when implementing the full set of allowable operational actions. In this case, the Reliability Assessment will provide insight into any unmet criteria or bottlenecks preventing the gas system from operating reliably with or without Aliso Canyon storage field.

Production Cost Modeling: Introduction

The availability of natural gas storage, particularly in the western Los Angeles Basin, has several important interactions with the overall gas pipeline system in regulating pressure, storing or releasing natural gas, and providing gas supply at locations distant from receipt points. Aliso Canyon also produces effects on the electricity system by providing readily available supply near the power plants that will burn the natural gas.

By performing PCM, CPUC staff seeks to quantify the effects on the electric system that will be produced by the elimination or minimization of Aliso Canyon Gas Storage Field. CPUC staff will perform PCM analysis to provide necessary inputs to the Reliability Assessment in the hydraulic modeling as well as test the effects on electric system reliability and electric production costs that are the result of gas limitations found by the Reliability Assessment.

The Aliso storage field primarily interacts with electricity generating plants in the Western Los Angeles Basin, which are either in the CAISO balancing authority or the LADWP balancing authority area. Elimination or minimization of the Aliso storage field will affect these plants' ramping ability, their ability to start up on short notice, and other operating parameters, which in turn may affect electric system costs and reliability. In addition, under the 1-in-35 extreme peak design standard, complete curtailment of a larger group of electric generators may be required to protect core customer gas supply.

CPUC staff will perform PCM analysis to produce two main data sets that input into the hydraulic model and one dataset that will assist with the Implied Market Heat rate analysis in the Economic Modeling section. CPUC staff will produce hourly gas demand from electric generators representing "Unconstrained Gas" and "Minimum Local Generation" scenarios.

The Unconstrained Gas scenario represents conditions where electric generators can start up, generate, and ramp according to the technical parameters of the individual power plants, without constraints caused by the pipeline or the gas supply curtailment. The Minimum Local Generation scenario represents conditions where pipeline and gas storage constraints have forced curtailment of electric generation. In this scenario, electric generators would be curtailed except for the minimum amount of generation deemed necessary by the power flow analysis discussed below.

Hourly gas use derived from electric generator dispatch will be aggregated by month, with hourly profiles selected to represent the 1-in-10 peak design day and the 1-in-35 extreme peak design day in each of the Unconstrained Gas and Minimum Local Generation scenarios. This data will be used for the hydraulic model.

To answer the questions raised in the OII, the PCM analysis will specifically produce results quantifying the reliability effects (in terms of "Loss of Load Expectation" or LOLE) and cost effects created by changes in total electric production cost resulting from removal of gas supply at Aliso.

Production Cost Modeling Analysis

CPUC staff has developed a standard process for completing PCM analysis to support the Resource Adequacy and Integrated Resource planning proceedings, which will be applied to this OII for consistency. The approach and development of the associated dataset is described in the "Unified Resource Adequacy and Integrated Resource Plan Inputs and Assumptions – Guidance for Production Cost Modeling and Network Reliability Studies" (Unified Inputs and Assumptions) and is available on the CPUC website.[24] The Unified I/A also describes the modeling process for performing stochastic reliability studies in a determined order based on LOLE and Effective Load Carrying Capability (ELCC) metrics.[25]

However, CPUC staff made some assumptions unique to the PCM modeling in this OII. In addition to the economic buffering effects of nearby gas storage on core and noncore

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

[25] The Unified I/A will be updated to include changes required by SB100, signed into law on September 10, 2018 when it is revised for the 2019 Reference System Plan in early 2019.

gas prices, Aliso Canyon also provides either extra stored gas when demand is higher than flowing supply or the ability to react to gas pressure swings at various nearby delivery points with greater speed and flexibility than would otherwise be the case. Both of these effects are important to the electric system. To capture the effects of the elimination or minimized usage of the Aliso Canyon storage field, CPUC staff must make assumptions about how to reflect the absence of nearby stored gas on the operations of power plants within a PCM framework.

In the end, several data inputs and outputs from the PCM analysis will feed into the hydraulic modeling analysis. In particular, the expected hourly gas use needed to operate electric generators at various points of the SoCalGas gas transmission system over the hours of a day will affect the ability to serve core gas demand elsewhere, impacting the flow and pressure on network elements that the hydraulic model will need to simulate.

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 Inputs and Assumptions.

The CPUC will use the SERVM model and the assumptions developed in the Unified Inputs and Assumptions to simulate electric generation dispatch for the Unconstrained Gas scenario. Hourly profiles for the hydraulic modeling will be created for this scenario.

For the Minimum Local Generation scenario, the power flow model will prescribe the local generators in CAISO and LADWP areas to be protected and dispatched in the PCM model. The electric generation dispatched in the PCM will be transformed into hourly gas demand profiles that are tested in the hydraulic modeling. Should the hydraulic modeling determine that electric generation infeasible on an hourly or total daily basis, staff will modify the standard operating inputs in SERVM to implement a third "Constrained Gas" case representative of the outcome of hydraulic modeling and report that to parties.

PCM Modeling will be performed according to the process laid out below:

1. **CPUC staff will simulate the effects of the 1-in-10 design day standards.** CPUC staff will perform the PCM study under the Unconstrained Gas scenario to determine reliability and cost of the existing electric system without any changes made in the three study years of 2020, 2025, and 2030. This study is similar to the work performed for the Integrated Resource Plan proceeding as described in the Unified Inputs and Assumptions document.
   - CPUC staff will develop forecasted hourly generation profiles based on the hourly results of the Unconstrained Gas scenario in the PCM study for the set of generating plants in the SoCalGas system, grouping generators by gas delivery node corresponding to the Reliability Assessment in the hydraulic model.
   - CPUC staff will oversee and evaluate the hydraulic modeling. The results of that modeling will inform constraints to place on power plants related to Aliso Canyon curtailment.
2. **CPUC staff will simulate the effects of the 1-in-35 design day gas demand and the curtailment protocols in Rule 23.** CPUC staff will collaborate with CAISO and LADWP to evaluate how much gas generation is needed to meet FERC Local Capacity Area Resource Requirements. As much as possible, without releasing sensitive data, the results from the power flow studies will be released to parties in the proceeding. Those results will be incorporated into the PCM phase by preserving the availability of the Minimum Local Generation identified by the power flow study in the PCM, and ensuring that generation is available while all other generation relying on the SoCalGas system may be curtailed as needed to prevent overloading of the gas pipeline system, so as to implement the "Minimum Local Generation" scenario. The resulting gas demand profile shapes will be used as inputs to the hydraulic modeling analysis.
   - CPUC staff will include any curtailment information from the Reliability Assessment for the 1-in-35 (extreme peak) design day and identify any changes to operating parameters for individual power plants or groups of power plants then evaluate those changes in a PCM model.
   - CPUC staff will 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. Results to be reported are summarized below.

Reliability and Production Cost Outputs

Reliability Results

- Loss of Load Expectation (LOLE)
- Loss of Load Hours (LOLH)
- Expected Unserved Energy (EUE)
- Power flow results indicating Local Generation requirements in CAISO and LADWP areas

Electric Production Cost Results

- Fuel Cost
- Variable Operations and Maintenance
- Emissions Costs
- Generation and fuel use by resource class

Creation of Daily Gas Usage Profiles

Additionally, CPUC staff will use PCM to create daily operating profiles for power plants that rely on the SoCalGas gas delivery system to represent the 1-in-10 peak and 1-in-35 extreme peak operating conditions for each study year. These hourly profiles will be used in the hydraulic model Feasibility Assessment and Reliability Assessment. This consists of running SERVM to model hourly electric generation gas demand without gas constraints, exporting hourly dispatch and fuel use profiles, then selecting the appropriate profile to use from the large dataset of possible dispatch profiles. Staff will then select two 24-hour profiles for each month to represent the 1-in-10 (peak) and 1-in-35 (extreme peak) gas use design days will be run. A more detailed explanation of the process staff will follow is laid out below:

1. Simulate hourly dispatch over all hours (8,760 hours total) of the study year, preserving Minimum Local Generation.
2. Export hourly electricity generation profiles by individual power plant. Collect daily gas use for all plants in Southern California Edison (SCE), LADWP, and San Diego Gas & Electric (SDG&E) service territories then assemble daily electric generation shapes totaled across the three service territories, ranking them in order of descending total gas use and grouping them by month.
3. From a dataset that includes 365 days for 175 cases[26] (63,875 days total), select one day per month (out of approximately 5,250 daily shapes per month) that

[26] 175 cases derive from a combination of 35 weather years times five load forecast uncertainty levels

represents the 1-in-10 (90th percentile) level, and another day that represents the 1-in-35 (97.1th percentile) dispatch profile based on total gas use in that month. No scaling up to peak is required, as these shapes represent the study year in question already.

4. For purposes of the Feasibility Assessment CPUC staff will develop representative hourly electric generation that represents the 50% percentile dispatch patterns, based on total gas use for that month. In total, three sets of hourly generation profiles will be developed for nine months of 2020, and for two seasons of 2025 and 2030 each. This totals 39 hourly profile shapes (nine times three for 2020, and4 times 3 for 2025 and 2030).
5. If shapes are strongly similar for a whole season or across many months, profile shapes may be merged or dropped, but no less than four profile shapes will be created to represent a peak and an extreme peak condition for both the summer and winter seasons.
6. Daily gas use shapes for the selected day for each electricity generator will be aggregated by gas delivery point (usually each power plant has its own gas delivery point) and combined with the corresponding monthly shapes aggregated to zip code selected to represent core gas for the corresponding month and study year and loaded into the hydraulic model.

Changes to Plant Operating Parameters to Implement Gas Constraints

CPUC staff has gathered the necessary operating data to implement a PCM model representing a condition without curtailment or shortage of fuel availability. To implement various levels of Aliso Canyon unavailability in SERVM, staff will need to implement the effects in terms of how power plants will dispatch.

In the event of Aliso closure, power plants in Southern California will need to schedule gas well in advance to allow for delivery from a distant gas delivery hub and to prevent imbalances that were previously mitigated with storage. CPUC staff simulates this effect in SERVM by restricting the ramp rate and increasing the startup up time and extending the startup profile of plants in the Western LA Basin.

CPUC staff will also seek to simulate the effect of a Rule 23 curtailment on a 1-in-35 (extreme peak) gas demand day by limiting total gas volume to all the power plants in the SoCalGas system and simulating the effect of a total volumetric constraint over a group of power plants. The total volumetric constraint will be set at the level resulting from the hydraulic model Reliability Assessment 1-in-35 (extreme peak) design day modeling.

Production Cost Modeling: Drawing Conclusions

PCM analysis will be completed to answer the fundamental question of whether the elimination or minimization of the Aliso causes any significant reliability effects, such as a change in either LOLE, LOLH, or EUE by 5% or more, or a change in electric production costs by 5% or more.

CPUC staff will perform this assessment by first simulating the Unconstrained Gas scenario for the 1-in-10 peak design day, tabulating the reliability and cost results for the CAISO system and the LADWP system under that scenario, then simulating gas supply restrictions from the Hydraulic Model resulting from the Minimum Local Generation scenario. CPUC staff will compare reliability and cost metrics to see if any significant changes to reliability or electric production costs occur. If none occur, then it may be possible to conclude that the effects of minimizing Aliso produced limited electric system reliability effects outside of possible FERC Minimum Local Generation effects.

Economic Modeling

Outline of the Three Economic Models

The purpose of the economic modeling is to estimate the impacts of eliminating or minimizing the use of Aliso gas storage on SoCalGas' core and noncore natural gas ratepayers. CPUC staff will perform an economic study consisting of three statistical and econometric models. These models will use historical and future gas prices and gas billing data to analyze, estimate, and predict the relationships of the gas system to rate impacts for core gas customers. Staff will study possible effects on electricity prices in the CAISO resulting from gas curtailment. The economic analysis also examines the causes and impacts of natural gas price volatility.

CPUC staff will perform three analyses as part of the Economic Modeling component. The three adopted analyses are listed here and described below:

- **Part 1 Volatility Analysis** - will estimate and assess the source of volatility of natural gas prices at SoCalGas CityGate.
- **Part 2 The Impact of Natural Gas Storage on Ratepayers' Bills** - will quantify and compare the impacts of gas storage availability on ratepayer costs for core customers in similarly situated geographic areas.

- **Part 3 The Impact of Tighter Gas Supply in SoCalGas System on Power Generation in the CAISO Territory** - will assess the impact of storage availability on CAISO wholesale power generation by analyzing the impacts of gas availability on electricity prices and power plant dispatch patterns.

Part 1: Volatility Analysis

In addition to improving reliability, storage can be 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. Finally, natural gas storage provides a means to mitigate imbalances and penalties related to imbalances during operational flow orders (OFOs), as any imbalances in gas deliveries can either be supplemented with gas withdrawn from storage (if deliveries are too low) or injected into storage (if deliveries are too high).

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 historically had the option to pay for storage rights.[27] 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 be severely reduced compared to historic norms, leaving noncore customers more exposed to market volatility and penalties related to changes in their dispatch or gas use that they encounter after their daily gas is scheduled. 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.

CPUC staff will conduct a volatility analysis of SoCalGas CityGate natural gas commodity prices. The purpose of the volatility analysis is to study the economic impact of uncertainty on SoCalGas customers – not to study reliability. Economically speaking, uncertainties are costs. Since costs raise prices, and volatility is an uncertainty, volatility raises prices. The aim of this analysis is to assess the source of SoCalGas CityGate price

[27] For more information: http://www.cpuc.ca.gov/natural_gas/

volatility. Volatility could be due to weather, lack of storage, outages or other factors over time. The volatility analysis will look into SoCalGas CityGate prices before and after the capacity reduction at Aliso in 2016 and test whether curtailment of Aliso Canyon gas storage is a significant factor in explaining gas price volatility. In terms of analysis, this means that we will attempt to disprove the null hypothesis that curtailment of Aliso Canyon gas storage was NOT a significant factor explaining gas price volatility.

CPUC staff will perform a time series model with explanatory variables to study the relationship between the daily price return of the SoCalGas Citygate natural gas pricing hub and explanatory variables.

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.

The potential list of variables will include the daily natural gas storage inventories in SoCalGas storage facilities, the reduced capacity of the pipeline system due to pipeline outages, beginning-of-the-day inventory level, day-of-week variables, heating degree days (HDD), cooling degree days (CDD), and variables indicating season and month, the incidence of an operational flow order, the dispatched quantity in the Day Ahead Electricity Market minus the dispatched quantity in the Real Time Electricity Market, and other variables as listed below.

CPUC staff will evaluate volatility in SoCalGas natural gas prices with the Generalized Autoregressive Conditional Heteroscedasticity (GARCH) model [28] 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.

The initial model will take the structure below:

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

- *C* is the constant term (the intercept).

[28] For more information on GARCH: https://pubs.aeaweb.org/doi/pdfplus/10.1257/jep.15.4.157

- R_t is the price returns at time t (dependent variable).
- $\varphi_i R_{t-1}$ 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.
- $\beta_k X_t$**:** β is the coefficient or coefficients of interest to be estimated. Xt is a set of the potential explanatory variables to be tested and included in the model. This set includes:
  - Beginning-of-the-day inventory level.
  - Day-of-week dummies.
  - Heating degree days (HDD) and cooling degree days (CDD)
  - Season and month dummy variables
  - High OFO Dummy variable set to 1 in the event of a High Operational Flow Order.
  - Low OFO Dummy variable set to 1 in the event of a Low Operational Flow Order.
  - Basis differential.
  - The customer imbalance in the SoCalGas system.
  - Dummy variable set to 1 if there is a Curtailment Watch.
  - An interaction variable X4 which represents the effect of storage at different levels of BTS available pipeline capacity. This variable is meant to represent the interaction of storage inventory and BTS available pipeline capacity. This variable is constructed as follows:
    - Variable X1 represents total daily storage inventory across SoCalGas territory.
    - Variable X2 represents the firm pipeline capacity usage level. This variable would equal the ratio of daily total scheduled gas to daily total daily available operating capacity. This is variable is a proxy for the pipeline outages.
    - Dummy variable X3 indicates whether variable X2 is equal to or greater than 80% or less than 80%.
  - The dispatched quantity in Electricity Day Ahead Market - the dispatched quantity in Electricity Real Time Market.
  - Storage change.
  - Storage deviation from its expected level.
- εt is the stochastic disturbance.

The table below shows the variables and data sources

Table 2: Part 1 Data Sources

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, Henry Hub, El Paso San Juan Basin and El Paso Permian Basin	NGI
Daily available operating capacity and Scheduled Gas in SoCalGas system	DR and Envoy
The customer imbalance in the SoCalGas system	Envoy
Curtailment Watch	DR
The dispatched quantity in the Electricity Day Ahead Market and the dispatched quantity in the Electricity Real Time Market	CAISO settlement data

Part 2: The Impact of Natural Gas Storage on Gas Commodity Costs

To quantify the effect of storage availability on ratepayers, an econometrics technique called "Difference in Differences" (DID)[29] will use used. In the DID model, outcomes are observed for two groups during two time periods. One of the groups (treatment group) is exposed to the treatment in the second period but not in the first period. The other group (control group) is not exposed to the treatment during either period. The DID approach can be applied to repeated cross sections of a group or to panel data over a certain time 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. The Difference in Differences analysis is not meant to be a reliability assessment. The DID analysis is meant to quantify the effect of storage availability on the gas commodity charge part of core customers' bills. This analysis seeks to test the following hypothesis: capacity reduction in Aliso Canyon gas storage did NOT significantly affect the amount core customers paid in commodity cost for natural gas.

[29] For more information on Difference in Differences: http://www.nber.org/WNE/Slides7-31-07/slides_10_diffindiffs.pdf

CPUC staff will use the commodity cost from core customer billing data for SoCalGas (treatment group) and PG&E (control group) core customers by household with zip codes representing the same areas (similar in weather, household size, income, etc.) before and after the Aliso Canyon leak required curtailment of the Aliso Canyon storage facility. CPUC staff will study commodity costs for customers in zip codes where SoCalGas and PG&E service areas overlap, including the towns of Arvin, Bakersfield, Fellows, Fresno, Del Ray, Fowler, Paso Robles, Selma, Taft, Tehachapi, and Templeton.

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 CPUC staff to estimate the effect of reduced capacity of the Aliso Canyon natural gas storage facility on the commodity cost component of daily natural gas bills of similar ratepayers in the same zip codes but with differing exposure to curtailment of natural gas storage.

If the difference in natural gas commodity costs before and after the Aliso Canyon leak for SoCalGas customers is equal to the difference in gas commodity costs before and after the Aliso Canyon leak for PG&E customers, then the DID estimate is zero and not statistically significant. A DID of zero would mean that there is no relationship between variation in availability of Aliso Canyon storage and differences in prices between SoCalGas prices and PG&E prices. On the contrary, if there is a relationship between the storage and investigated outcomes, then the DID estimate will be statistically significant and the conclusion would be that differences in gas commodity prices between similarly situated customers in SoCalGas territory and PG&E territory would be the result of the Aliso outage. Also, the model will include control variables such as the pipeline outages to distinguish between the effect of storage and the pipeline outages.

Two differences in outcomes are important: 1) the difference in commodity costs in customer daily bills before vs. after the Aliso Canyon leak for the SoCalGas customers is (B2 −B1) and 2) the difference in commodity 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 zero and is not statistically significant. If there is a relationship between the storage and subsequent outcomes, then the DID estimate will be statistically significant.

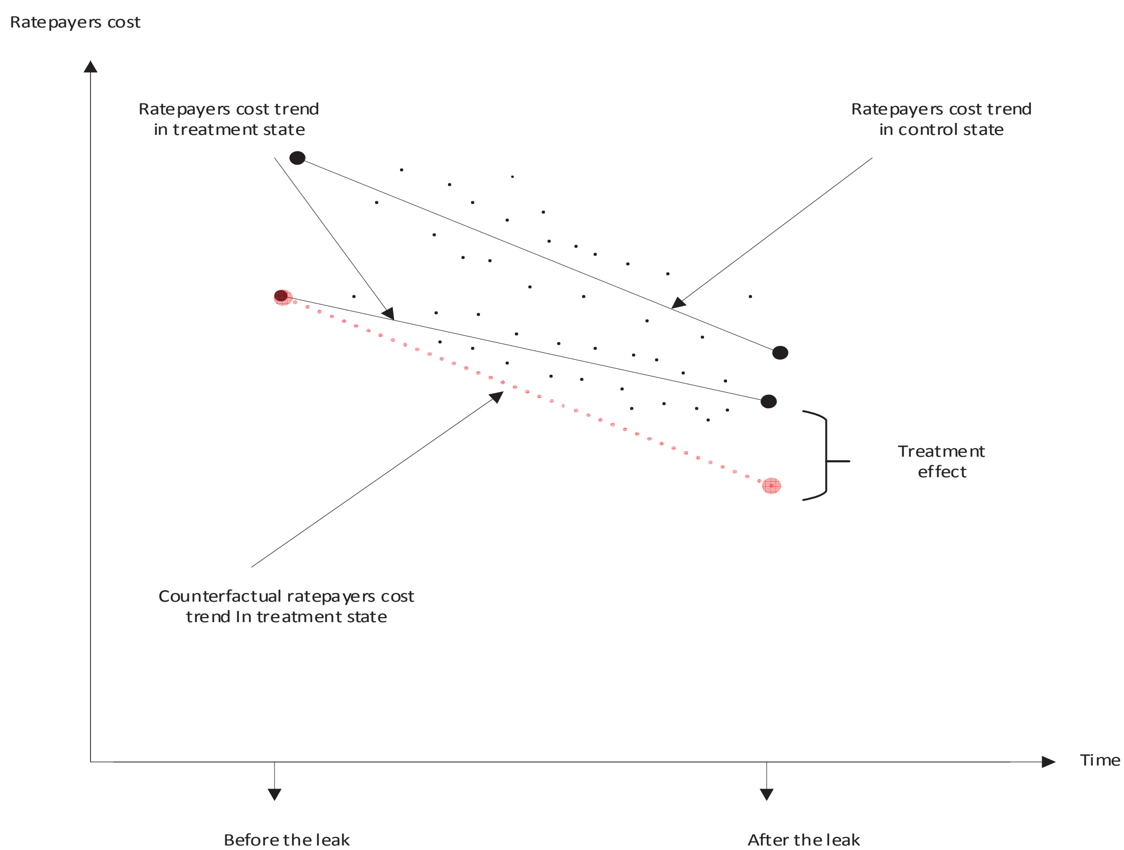
These estimates will be derived from a regression model:

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

- *Yst* the observed outcome in group s and period t. In this case, it is the natural gas commodity cost component of individual ratepayer's daily gas bills.
- *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 the coefficient of the treatment effect, which is the coefficient of interest. The estimate of *β3* is identical to the double difference: (B2−B1) − (A2−A1).
- βkX: βks are the coefficients to be estimated. X is a set of the potential explanatory variables to be tested and included in the model. This set of explanatory variables could include variables for low-income households, storage inventory levels, and pipeline capacity, but data need to be evaluated first.
    - Beginning-of-the-day gas storage inventory level.
    - Low income households' variable.
    - Heating degree days (HDD) and cooling degree days (CDD) or seasons or months.
    - Operational flow order. OFOs variable will consist of two sets: low and high OFOs.
    - A dummy (X2) to indicate whether variable X1 is equal to or greater than 80% or less than 80% (To construct X2, CPUC staff will use a variable (X1) which represents firm pipeline capacity usage level. This variable would equal the ratio of daily total scheduled gas to daily available operating capacity). If there is multicollinearity between X1 and X2, CPUC staff will address it when reviewing the output results.
    - Basis differential: SoCal Border daily spot price – Henry Hub spot price.

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 commodity cost trajectory with respect to time before and after the reduced capacity of the Aliso Canyon storage field.

Figure 5 Causal Effects in the DID Model



The table below shows the data source:

Table 3: Part 2 Data Sources

Variable	Data Source
Daily core gas customer bill data broken down by rate component	Data Request (DR) from SoCalGas and PG&E
Low income households	DR from SoCalGas and PG&E

Pipeline available capacity	
Daily storage inventory level by storage field in SoCalGas system	DR from SoCalGas
Daily cooling and heating degree days	DR from SoCalGas
Daily and monthly gas prices for: PG&E Citygate and PG&E Border, SoCalGas border, Henry Hub	NGI
Daily pipeline outages in SoCalGas system	DR and Envoy
Daily Operating Capacity	Envoy

Part 3: The Impact of Tighter Gas Supply in SoCalGas System on Implied Market Heat Rate in the CAISO Territory

The Aliso Canyon storage facility provides gas supplies to natural gas-fired power plants that play a central role in meeting regional electrical demand and helps them meet peak electrical demands during the summer months. Constrained gas supply from Aliso Canyon could lead to a decrease in the availability of natural gas in Southern California, which would lead to dispatch of power plants outside of Southern California. The increased dispatch and flow of electricity into Southern California may raise electricity prices through dispatching less fuel-efficient plants.

The purpose of the Implied Market Heat Rate (IMHR) analysis is to assess impacts on electric prices in CAISO by comparing the implied market heat rate of electric generators dispatched pre and post-Aliso leak to determine if there is a potential cause and effect between gas curtailment and power prices. This analysis can also be also be performed with forecast energy dispatch and forecast gas and electricity prices resulting from the PCM modeling to forecast implied market heat rate under different Aliso reduction scenarios. This analysis doesn't specifically address the reliability of either the electric or natural gas system, but instead seeks to quantify potential economic costs of reduced capacity at Aliso on dispatch of electric generators, as seen in an increase in electric power prices.

Implied Market Heat Rate

IMHR is a means of translating hourly electricity prices into a cost curve where marginal power plants can be ordered and compared against each hour. If the IMHR increases, that means less efficient power plants (which use more fuel to produce a MWh of electricity) can effectively recoup their costs. Thus, IMHR is an indicator of underlying costs of the electricity market and can illustrate how efficient a power plant must be to be considered "on the margin" and be the last one dispatched.

CPUC staff will analyze cost trends in the CAISO market to determine if Aliso reduction may have led to an increase in IMHR (and underlying electricity costs) and thus dispatched less efficient plants. It is a means of measuring the economic cost effects on the electricity market of reduction in availability of Aliso.

CPUC staff 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, the PG&E Citygate gas price, and the SoCalGas Citygate gas price. In addition, CPUC staff will conduct implied market heat rate analysis for the highest priced hours and the lowest price hours per year available for both Northern and Southern California. This way we can compare trends in each area of CAISO and check if there is an interaction.

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 market heat rate can be obtained by dividing electric price by the natural gas price.[30]

The implied market heat rate is calculated as shown below. The day-ahead electric price and generation data will be collected from the CAISO's Open Access Same-time Information System (OASIS) site

For Northern California:

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[30] For the definition of Implied Heat rate according to the U.S. Energy Information Administration, see: https://www.eia.gov/tools/glossary/index.php?id=I:
A calculation of the day-ahead electric price divided by the day-ahead natural gas price. Implied heat rate is also known as the 'break-even natural gas market heat rate,' because only a natural gas generator with an operating heat rate (measure of unit efficiency) 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.

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

$Implied\ Market\ Heat\ Ratet$ is the daily implied market 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 each day for the TAC_NORTH area.

For Southern California:

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

$Implied\ Heat\ Ratet$ 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 each day for the TAC_ECNTR and TAC_SOUTH area combined.

To replicate this analysis for future forecasting, CPUC staff will use the electricity prices and power plant dispatch profiles that result from the PCM analysis performed by CPUC staff in order to estimate implied market heat rate in forecasted future years (2020, 20205, and 2030).

Table 4: Part 3 Data Sources

Variable	**Data Source**
Daily and monthly gas prices for: SoCalGas Citygate, PG&E Citygate, SoCalGas border	NGI and NAM (for monthly future prices)
The dispatched quantity in Electricity Day Ahead Market- The dispatched quantity in Electricity Real Time Market	CAISO settlement data the CPUC receives via annual subpoena

Hourly Electricity Price and Generation by region	OASIS and SERVM

Data sources

To complete all three analyses outlined above, CPUC staff will collect data from various sources. Most of the data will be data requested from SoCalGas and PG&E, while other data will be collected from Natural Gas Intelligence (NGI), ENVOY[31], SERVM, NAMGas and OASIS.

CPUC staff 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 several delivery points including SoCalGas Citygate, PG&E Citygate, SoCalGas border and Henry Hub, daily available operating capacity as a proxy for pipeline outages, daily operational flow order, future natural gas price and daily residential natural gas bill data.

[31] ENVOY is SoCalGas' Internet-based gas transportation management system https://envoy.sempra.com

APPENDIX A: List of Assumptions

Hydraulic Modeling

a. Interstate supplies are available at their firm capacities without interruptions.
b. The hydraulic model does not extend beyond the state of California, i.e. multi-state weather events or pipelines and wells upstream of the receipt points are not modeled. Instead, during steady and transient simulation, a boundary condition must be applied at the receipt points, i.e. the pressure or flow rate must be specified.
c. Multi-day peak or extreme peak cold weather (or hot weather) events are not considered, since all simulations are executed for 24 hours. Extending the simulation time will increase the computational time and cost proportionally.
d. The hydraulic model does not simulate the underground storages, wells, or accompanying facilities. It simulates the steady and transient flows within the SoCalGas pipeline network. The underground storages are imposed on the hydraulic model with known injection and withdrawal capacities when needed.
e. Difference between day-ahead (DA) scheduling and real time (RT) gas consumption or burn is not modeled, since this would require simulating the "decisions" of core and non-core customers. In the future, this could be done using a statistical approach with reduced (or simplified) modeling in order to provide an estimate of the difference between both.
f. The maximum rate of change of core gas demand is proportional to the magnitude of the peak.
g. During peak or extreme peak days, Economics do not play a major role.
h. Prudent actions by the pipeline operator are assumed.
i. Some assumptions are inherited from the simulation software used. These assumptions are usually a common practice. For example, if Synergi software is used, at least the following assumptions are probably inherited:
    i. 1-Dimensional flow within the pipeline.
    ii. Isothermal flow of natural gas (i.e. constant temperature).
    iii. No sudden changes in the system are allowed, i.e. valve and compressor settings should be changed slowly.

APPENDIX B: Summary of Comments and CPUC Staff Responses

Name/Organization:	Comments:	CPUC staff Responses:
Environmental Defense Fund Category: Environmental organization	• Pleased to see several of our comments integrated in this version, such as the use of AMI or smart meter technology to determine load profile shapes that can be scaled up. • Framework still focuses too much on the storage side of Aliso Canyon and does little to address changes in gas demand as the share of renewables increases. • EDF agrees with PDR or Honor Rancho substituting the reliability role that Aliso historically provides; this is certainly possible assuming inventory levels are maintained between 60% and 80%. • Reliability Assessment should determine minimum and maximum levels of gas in underground storage needed. Right now, solely monthly minimums. • A 2011 report demonstrates that a relatively small change to SoCalGas's gas receipt system can address Wheeler Ridge and Honor Rancho pipeline competition. • This version removed the assumption that total gas receipts are 95% of total scheduled capacity, as EDF recommended in June 2017 comments. The 95% assumption should be added back in.	• We allow for changes to gas use in the electricity generation profiles generated in PCM. Otherwise we are analyzing reductions in core gas use in Phase II • This cannot be concluded without first running the hydraulic modeling. • For now, the focus is on the reliability of the gas system. Maximum levels can be looked at later as it is more relevant to the pipeline operator. • We are evaluating that study and will look at it in more detail in Phase 2 • The final version of the framework makes no assumptions about scheduled vs. received gas, but rather on the zonal utilization. Implementing both conditions will result in an over-prescribed model.

	• On page 17, in the sentence, "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." The word "injections" should be replaced with "withdrawals." • Although an integrated model between the gas and the electric side of the equation is not commercially available, models of the intra-day gas system are available and should be used. In addition, the assessment should consider intra-day gas market rules, such as an imbalance market. • Still unclear which market rules are incorporated in the Framework • Identify the "full set of allowable operational actions" • EDF was pleased to see that data from the natural gas pipeline networks will be set up in Synergi and stored in a case file reported to the CPUC and Los Alamos for inspection and review. • California Gas Report should not be used in 2024 or 2029 assessments; it will not consider changes in the gas market or the reduced need for gas in future years. • Supports the "determination of the plausible unplanned pipeline and storage outage events . . . to be carried out using historical records" rather than relying	• Agreed; change made • Synergi is an intraday model of the gas system, and while the models are not totally connected, we will integrate the results of the Hydraulic Model with the PCM model as much as possible • Market rules are not applicable to a stress test reliability simulation. • Curtailments as identified in the Scenarios Framework • CPUC staff plans to use the same forecasts until a more credible source is found.

	on SoCalGas to determine the "plausible unplanned pipeline outage."	
	• Noncore, non-electric hourly gas load profiles from SoCalGas should be the same day demand using hourly consumption.	• This is not meant to be an actual day; this is supposed to be an artificial day created to stress test the gas system. For that reason, we have not attempted to keep all hourly gas profiles correlated.
	• Instead of asking how we can operate our gas system in a way that minimizes the need for Aliso Canyon, the study asks how Aliso Canyon can be relied upon to support existing gas system.	• We are attempting to see if we can remove Aliso and still maintain reliability
	• The model should simulate multiple scenarios with varying levels of base load demand.	• We will model design day standards and curtailments according to current rules
	• For non-PDR gas storage, if there is excess gas system capacity, the assumptions about the net injections should also include maximums to account for needed injections to keep pressure from exceeding the capabilities of the pipes.	• Each field has a maximum injection rate that will be used as the upper bound for injections. Withdrawal rates will depend on the level of gas in storage.
	• EDF noted that a section for potential future analysis was added. A sensitivity analysis to estimate needed additional actions or alternative operation actions to reduce storage at Aliso Canyon to zero is what is required by SB380.	
	• Need more information on how Production Cost Model "will include control variables such as the	• The PCM does not state it will do this; the economic model does. We will have a term in a regression and see if this term is a statistically significant variable or not.

	pipeline outages to distinguish between the effect of storage and the pipeline outages." • Conduct Feasibility Assessment before Reliability Assessment.	• The assessment can start with either, but staff chooses to start with the reliability so that the minimum gas storage schedule is available before conducting the feasibility assessment.
Name/Organization: Southern California Publicly Owned Utilities Category: Local government	Comments: • The Final Proposal reflects substantial progress in refining the scenarios that will be modeled. • Using aggregated data from the SoCalGas Advanced Metering Infrastructure system as now proposed by the Energy Division should enhance the hydraulic modeling of the SoCalGas transmission and distribution system.	
Name/Organization: Dr. Issam Najm Category: Private citizen	Comments: • Page 6 states Aliso's "key" role because of the slow speed at which gas travels. Pressure travels at the speed of sound and can be mitigated very rapidly by increasing pressure at locations much farther than Aliso Canyon. • Storing gas for price arbitrage can happen anywhere in the system between production and use, and there is nothing unique about Aliso Canyon in this regard. The significance of Aliso should not be overstated.	CPUC staff Responses: • While pressure waves (variations) travel at the speed of the sound, the natural gas itself doesn't adjust its velocity (and hence mass flow rate) as quickly.

	• The physical boundaries of the hydraulic model are not clear. • On page 11, Energy Division states all data is stored in a "case file." I ask that the case file be shared with all parties to the proceeding. If SoCalGas requires the CPUC to keep this file confidential, I ask the ALJ for a hearing so SoCalGas can provide confidentiality reasoning.	• The boundary conditions are from the receipt points to delivery points only on the SoCalGas system. We will attempt to provide a map in the future to help in visualizing
	• On page 12, Energy Division states that historical hourly data for 1-in-10 or 1-in-35 is not available. This is can be calculated because SoCalGas has hourly injection/withdrawal data and hourly receipt data, and all non-core customers have hourly burn data.	• CPUC staff is looking to derive the individual load profiles shapes for individual delivery points, not the aggregate core gas use profile for the entire customer class, therefore smart meter data must be used.
	• On page 15, under Flowing Gas Supplies, Energy Division provides a preliminary analysis of historical zonal data. How were these capacities determined? What is used as the capacity? If these are the actual flowing gas values during these periods, then they do not represent capacities. They only represent what SoCalGas chose to flow through the transmission lines during those times. Energy Division should reconsider the use of these values in setting the capacities. For hydraulic modeling, Energy Division should use the rated capacity of each pipeline as long as the model predicts the pressure to remain within acceptable	• This is based on analysis of historical data which may or may not include the effect of outages into account. The lower capacities could be a result of customer nominations, scheduling, or operational decisions. For the reliability analysis, we added one run that assumes nominal capacity to test sensitivity of results to zonal capacity.

	values. If the Energy Division wants to apply a safety factor by reducing the capacity by 5% or 10%, then it should be stated based on that criteria. • On page 23, under Feasibility Assessment: Simulation Outputs, I ask that Energy Division provides all parties with an assessment of what specific “bottlenecks” caused it to be infeasible.	• Modeling can only reveal the first bottleneck, not subsequent ones, unless further modeling is performed after “fixing” the first bottleneck.
Name/Organization: The Utility Reform Network (TURN) Category: Consumer advocacy organization	Comments: Hydraulic Modeling • Appreciates the substantial effort Energy Division has spent over the last year developing this Framework and believes it will be useful for evaluating the issues posed by the loss of some or all of Aliso Canyon • Concerned that simply “scaling up” hourly loads from a non-peak gas demand day to a peak or extreme peak gas demand day may yield a load shape that overestimates the maximum hourly load and underestimates load in hours adjacent to that hour of maximum demand; hours adjacent to the maximum demand hour may be misstated. • Recommends Energy Division use some degree of “scaling out” to develop hourly core gas demand load shapes for peak and extreme peak days, rather than simply “scaling up” all of a recorded shape’s hourly loads by the same factor. See Figure 2 for example of	CPUC staff Responses: • CPUC staff will be “stretching” hourly core gas demand profile shapes by both preserving total over a day and peak in an individual hour – that is to prevent what TURN is concerned about. There is a similar issue in electric hourly profiles when scaling up just to peak. This may not be perfect, but staff believes it is the best feasible option. Only the core shapes will be stretched – the non-core EG shapes come directly out of the PCM.

	“scaled up” vs “scaled out.” Scaled out reallocates peak to hours surrounding the recorded shape’s maximum hourly demand to reflect customers’ possible usage in such hours. • Evaluate extreme peak day to determine if “peak hour” should be scaled by some fraction of the actual ratio	
	Production Cost Model • TURN recognizes that modeling simulation of Rule 23 and other modeling techniques to mimic lower gas flows and pressures may not be straightforward in production cost models and appreciates ED’s interest in pursuing reasonable approaches to this modeling challenge.	
	• Energy Division should recognize the necessity of maintaining some level of electric service as a necessity to maintaining customers’ gas heating capabilities. Rule 23 allows for curtailment of EGs but note that core customers will also need electric service to operate gas heaters’ circulation fans.	• We envision a sequence of studies, beginning with the “Unconstrained Gas” scenario, and continuing to curtail more electric generation pursuant to Rule 23 section C.1(2) to alleviate overpressure conditions. If pressure cannot be returned to normal range, then curtail more as in C.1(4) and rerun the hydraulic model.
	Senate Bill 100 • Data used for Production Cost Model should reflect SB 100 as soon as possible.	• SB 100 will be implemented first in the IRP proceeding, and updates made there will flow into this modeling. When we

	• Increased renewable generation will reduce total gas demand in California; however, may increase the need for electric ramping products.	perform PCM next year, we will be consistent with the SB100 case in IRP
Name/Organization: Magnum Energy Midstream Holdings Category: Natural gas storage company	Comments: • On June 27, 2018, Magnum announced an open season for the Western Energy Storage and Transportation Header Project ("WEST Header Project"), a new 650-mile large-diameter interstate natural gas pipeline designed to move gas bi-directionally between receipt points and Magnum's gas storage facility; pleased with the responses so far. • The WEST Header Project will provide true bidirectional, intra-day, no notice, hourly load following, peak hour supply reliability and traditional storage and transportation service to meet the current and future hourly demands of the Western Energy Corridor • Pleased to hear at the July 31, 2018 workshop that parties will have the opportunity in Phase 2 to propose additional scenarios for modeling, including the addition of new infrastructure like Magnum's WEST Header project that could potentially mitigate the loss of Aliso Canyon deliverability.	staff Responses: • The Commission will provide a process for assessing alternatives to Aliso in Phase 2.

	• Commission should provide further guidance on how parties should present their proposed scenarios.	
	Hydraulic Modeling	
	• “Hydraulic Modeling: Introduction” states it is possible that a nearby storage facility may be able to substitute for the reliability role Aliso historically played. It is highly doubtful PDR or Honor Rancho can substitute for Aliso.	• We will need to perform modeling to test this hypothesis.
	• Concerned that using different load shapes from smart meter data as described will produce artificially low demand inputs for the Reliability Assessments for the 1-in-10 standard. Magnum believes the core load shape used for both analyses should be based on the load shape for the highest monthly peak day, with the only difference being the extent to which the hourly demands are scaled up.	• Approach has been changed to derive only the highest shape. See Scenarios Framework
	• A scenario for planned and unplanned outages should be run as part of the Reliability Assessment.	• We are performing a sensitivity with full operating capacity (no outages) and also performing modeling at 85% utilization (which could imply some impact from outages) and we are also studying the impact of outages on operating capacity. We have added significant study to further explore the effects of outages in the Framework.
	• Wants CPUC to expand on “additional actions or additional operational actions” and include scenarios	• Additional actions are curtailments as identified in the Scenarios Framework

	similar to what they are proposing. Or make the clarification in a scoping memo.	
Name/Organization: Coalition of California Utility Employees Category: Labor organization	Comments: • If models 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," then it is necessary to include situations that are both mild and those that stress the system more severely. CPUC staff intends to model only one pipeline outage (see page 45). • On page 20, "abnormally mild" is not defined, and "stressed conditions" are actually not infrequent; therefore, they should be included in the framework. • The PCM analysis is insufficient because it fails to include realistic scenarios that examine the impact of electric power transmission outages or deratings, natural gas plant outages or deratings, or high demand on natural gas power plants because of low wind or solar production. • On page 30 "well in advance" is not quantified and explain what changes to power plant ramp rates and startup times Energy Division proposes. • It is unclear whether Staff's proposed hydraulic modeling accounts for the need to schedule power plants well in advance. What happens if, for instance,	CPUC staff • We have detailed the outage analysis to develop more rigorous assumptions for modeling • This word has been removed. The system is assumed to be typical during the feasibility study with both planned and unplanned outages considered. • The PCM analysis will develop a good distribution of gas use from multiple levels of wind and solar, as well as gas plant outages. The PCM relies on the IRP framework, which is robust. • We will need to study how much to change ramp rates when we begin to perform modeling. • This is not a hydraulic modeling question. In reality this would mean an OFO.

	plants schedule gas delivery in advance, but then do not take delivery because they do not run (for either economics or reliability)?	
	Production Cost Model	
	• PCM should include realistic situations such as electric power transmission outages or deratings, natural gas plant outages or deratings, and high demand on natural gas power plants because of low wind or solar production.	• This is handled as part of the IRP analysis underlying the Aliso analysis.
	• Adhere to CAISO's suggestion to use both a bottom-up and top-down approach. There are valuable insights from top-down because it uses the power flow model to determine the adequacy of gas resources to meet minimum generation requirement.	• Agreed, top-down will be used as needed as this could prove time consuming.
	• Include western region impacts, as CAISO suggested. The recent WECC Study states that the "system has experienced multiple close calls and near misses" and concludes that "configuration of the gas/electric system combined with the loss of Aliso Canyon creates region-wide reliability issues. Modelling scenarios have identified DSW and Southern California in particular as reliability risks, with the DSW pipe disruption and freeze-off scenarios resulting in unserved energy and unmet spinning reserves. The results translate into	• The scope is southern California. The outcome of this OII will shed some light on whether modeling of upstream pipelines is needed, in which case, a more reduced-order model will have to be used.

	risked economic impacts on the order of several hundred million to a billion dollars.”	
	• More granular analysis, such as CAISO’s suggestion for 30-minute step sizes	• The sensitivity of the results to the time step (e.g. dispatching and gas profiles) may be investigated later to assess the need for shorter times steps.
	Economic Modeling • The models depend on historical data; if conditions depart from those we have seen historically, it will be difficult to apply the results to new condition.	• True, but we can still use a regression analysis with historical data to predict future values.
	• It is not clear how the volatility analysis addresses the question of “how reducing or eliminating use of Aliso would impact gas and electric reliability, electric costs and reliability, and natural gas commodity costs.” • Volatility analysis uses daily variations – how does the comparison of *daily* volatilities address the “traditional role” of Aliso to guard against *seasonal* price swings?	• Volatility analysis doesn’t directly address reliability. PCM will address the electric reliability and the hydraulic model will address the gas reliability. The comparison between SoCal City gate market and other relevant markets stems from the fact that the gas markets are integrated. The analysis will also test how significantly these factors impact the volatility in gas prices.
	• What is the hypothesis the GARCH or similar analysis is testing?	• This has been included in the Scenarios Framework.
	• How will conclusions be applied to the question of value of Aliso Canyon in reducing seasonal price variation, reducing price spikes, and reducing imbalance penalties?	• We are not seeking the value of Aliso Canyon. The increase in volatility can be translated to an increase in exposure to these other costs, as a percentage. We will provide more detail in Phase 2 as we develop our results.
	• Volatility analysis does not explicitly state what conclusions will be drawn	• The value of this analysis is to assess the most likely source of gas price volatility, and its frequency and magnitude from looking at recent price trends.

	• Proposed bill analysis is insufficient because it ignores potentially confounding effects or variables, such as underlying variables particular to PG&E • It is not clear what can be concluded from comparing historical market heat rates without considering differing factors in each region such as load, generation mix available (including imports), weather, outages, demand-side measures and gas prices. • The analysis fails to account for the need to run gas-fired power plants for reliability reasons only. So, how does this analysis answer the question of "how reducing or eliminating use of Aliso would impact gas and electric reliability, electric costs and reliability, and natural gas commodity costs?" • Unclear what conclusions can be drawn from Congestion Rent Assessment • Economic analyses must be revised to target the question of "how reducing or eliminating use of Aliso would impact gas and electric reliability, electric costs and reliability, and natural gas commodity costs.	• Staff uses PG&E as a control group to difference out the confounding factors that change over time and isolate the treatment effect. • This analysis will use historical data to assess the implied heat rate over time to determine if there is a potential cause and effect between gas curtailment and generation dispatch and power prices. This analysis also will analyze the future implied heat rate by using projected hourly market prices and hourly market dispatch that is reported out by the CPUC's PCM model • This analysis has been removed • CPUC staff believes the question will be answered
Name/Organization: Sierra Club	Comments: • Any "failed" simulations should yield actionable information for achieving the Legislature's goal of closing the facility; models must indicate the location,	CPUC Responses: • CPUC staff is stressing that pinpointing the first point of failure does not imply that it is the ONLY point of failure in

Category: Environmental organization	timing, and amount of gas demand reductions necessary to eliminate reliance on Aliso. • Clarify if failed Feasibility Assessments assist in planning demand reduction measures that will mitigate need to rely on Aliso. Indicate changes to the business-as-usual gas demand needed. • Unified I/A model will over-estimate the 2030 gas-fired capacity in Southern California by 1,256 MW if several LADWP and City of Glendale gas-fired units retire, and the municipal utilities do not build new gas-fired capacity. LADWP is currently studying alternatives to repowering gas-fired units Haynes, Scattergood, and Harbor, and Glendale is seeking alternatives to the new 262 MW Grayson gas plant. At a minimum, Energy Division should run scenarios without those units. • 2018 California Gas Report does not include SB 100. Energy Division should require SoCalGas to provide an update to its gas projects to reflect this change. • Updating gas demand forecast for EG does not appear to be complicated, as SoCalGas' workpapers state it's run in ARB Enterprise Software, it can be rerun with updates to RSP assumptions. • Unlike electric demand forecasts reviewed and adopted by the California Energy Commission, the Gas	the system. More modeling needs to be done after fixing the first bottleneck to find the second and so on. • Reliability assessment can shed more light on peak demand reduction since peak demand is the primary driver for using underground storage. • The PCM results will demonstrate the gas demand that is needed to run power plants in the future under IRP scenarios. We are confident that likely power plant investment will be studied in IRP. • SB 100 will be implemented in the IRP proceeding and the PCM study will produce non-core EG gas forecasts, which will be partial update at least. • CPUC staff plans to use the same forecasts until a more credible source is found.

	Demand Forecast is utility-developed and not subject to the same degree of scrutiny or agency approval. Energy Division should independently assess SoCalGas' 1-in-10 and 1-in-35 peak demand forecasts.	
Name/Organization: California Independent System Operator (CAISO) Category: Balancing authority	Comments: • CAISO agrees with the general framework and appreciates the inclusion of the CAISO power flow modeling to inform both the hydraulic and production cost modeling. • Scenarios Framework states the Reliability Assessment will model "a single plausible unplanned outage (pipeline or storage) that results in the maximum loss of aggregate gas send out." However, there are currently multiple outages. CAISO recommends incorporating multiple gas transmission and/or storage field outages in the hydraulic model. • Recommends the Commission also review electric reliability from a "top down" perspective in addition to the Commission-recommended "bottom-up" process. The "top down" approach would use the Commission's production cost modeling and hydraulic modeling initially to provide the CAISO information regarding the level of gas that would be available for	CPUC staff Responses: • We added a plan to analyze the most likely and impactful outages to add in hydraulic modeling. • It is possible to perform more PCM studies after the reliability assessment. However, this approach may be time consuming given the number of variations in distributing the excess natural gas.

	EG for both the 1-in-10 Peak and the 1-in-35 Extreme Peak conditions.	
	• Recommends that the Commission consider western region impacts that were identified in the Western Electricity Coordinating Council's recent Western Interconnection Gas-Electric Interface Study (WECC Study).	• This is out of scope
	• Concern that the production cost run may meet LOLE metrics for system wide reliability but would not be able to commit minimum generation needed for local capacity requirements. The CAISO suggests that the generation needed to maintain local capacity requirements be represented in the production cost modeling though a nomogram or a similar modeling mechanism that maintains a minimum amount of local gas-fired electric generation during peak load hours.	• CPUC staff intends to rely on inputs from CAISO and LADWP to determine the critical power plants that are required to maintain the local capability requirements (for the 1-in-35 standard or Minimum Local Generation scenario). The plants will then be modeled in the PCM and propagated to the hydraulic modeling. If the gas system cannot meet the requirements imposed by the PCM, then restrictions from the gas system may be propagated back to PCM and PF in a so-called top-down approach, in attempt to explore alternative solutions to maintain the 1-in-35 standard but we will see about that when we get the initial results.
	• Agrees that NERC reliability standards should be maintained in the modeling, but also notes that is only one of the reliability standards used for assessing reliability; should also reference FERC Local Capacity Area Resource Requirements.	• This is what we meant. We edited the report to reflect these NERC and FERC standards in the Minimum Local Generation Scenario.

	• CAISO also recommends that the Commission include information regarding Expected Unserved Energy (EUE) in addition to the Loss of Load Expectation (LOLE). LOLE information provides the expected accumulated amount of time (expressed in hours or days) during which a shortage of power is experienced, while EUE provides the expected amount of energy not supplied due to generation shortage from potential gas curtailments.	• CPUC staff intends to report both EUE and LOLH in addition to LOLE.
	• Currently states Aliso interacts with EG plants in the Western LA Basin. The hydraulic modeling should study all of the gas-fired generation connected to the SoCalGas system, including San Diego-Imperial Valley.	• We plan to model all plants connected to the SoCalGas system including San Diego in the Hydraulic Modeling. Staff believes this is a misunderstanding.
	• Commission should conduct more granular analysis in its hydraulic and production cost modeling; CAISO recommends conducting analyses with thirty-minute intervals (rather than hourly), for the production cost model. • Using historical data in the economic analysis may not provide forward looking information for future system conditions, but no objections to reviewing the historical data to determine if there is a potential cause and effect between gas curtailment and generation dispatch and power prices. However, the CAISO is concerned there	• Sensitivity of results to time step in PCM may be analyzed to confirm the largest acceptable time step. For pipelines, hydraulic modeling time step is a fraction of a minute and it is doubtful that disturbances within the order of a few minutes will affect the system, primarily because the system response is slow (damping, sound speed and operation) relative to the electrical system.

	is limited utility in using the results of historical events to determine the potential effects in the future as well as the degree of linearity of the comparison.	
Name/Organization: SoCalGas Category: Gas Utility	Comments: • Energy Division should sponsor one or more witnesses to testify regarding its Phase 2 analysis and respond to data requests to promote transparency and better inform interested parties. • The Commission need substantial evidence, which should be accomplished by providing for Energy Division discovery and testimony. • The hydraulic modeling assumes that the current nominal system pipeline capacities and non-Aliso Canyon withdrawal capabilities will persist through 2030; does not indicate intent to assess whether it is reasonable to assume that these levels will be maintained. • Does not consider changes in 2030 and beyond: there could be renewable natural gas and hydrogen, more outages due to new regulations now require field shut-ins twice a year and new technologies identifying more maintenance issues. Reduced capacity due to SoCalGas identifying instances to reduce pipeline operating pressures.	CPUC staff • Some sensitivity analysis was added to the reliability assessment to analyze the impact of outages on the nominal system capacity. This analysis should offer more insight. • Out of scope

	• At a minimum, Phase 2 should include scenarios where demand does not reduce as projected, where capacities do not return to higher levels, and should include sensitivity or probabilistic analyses for any inputs likely to be determinative in the mid and long-term cases.	
	• Re: page 10 of Framework, because the potential for customer operating emergencies are customer and condition specific, a Tariff Rule 23 declaration of an operating emergency should not be assumed for system planning. Therefore, the 1-in-35 design standard should assume full noncore curtailment.	• CPUC staff is aiming for reliable gas and electric systems and increasing the reliability of the natural gas system is the natural choice. Therefore, we will investigate the curtailment effectuations delineated in Rule 23, assessing both systems together to see how stringent the curtailment needs to be.
	• 1-in-35 assumption on page 13 is not consistent with page 10. Always assume full noncore curtailment.	• This has been rectified.
	• At 1-3 weeks per scenario, to complete more scenarios analyses in a shorter amount of time than what SoCalGas has estimated will require SoCalGas to dedicate additional staff, which will impact SoCalGas' other business processes.	• We are decreasing the simulations required in this Final Framework and may perform mass balancing in the Feasibility Assessment.
	• Agrees with successful model defined on page 18, as *minimum* conditions. Meeting the Scenarios Framework's minimum requirements should not end the analysis; rather, it should be the starting point in determining system reliability, including adequate flexibility and resiliency	

	• The role of Aliso Canyon on page 6 does not acknowledge the role Aliso Canyon's injection capacity plays in supporting the system. Aliso Canyon's injection capacity allows additional flowing supplies to be scheduled and received on the SoCalGas system by serving as an additional and significant "demand center".	
	• Framework may be overestimating the capabilities of Playa del Rey; for one day of full withdrawal, it takes approximately five days to refill the facility. Should revise assumed capabilities of the facility and system operations.	• Staff addressed this by restricting the use of PDR in our modeling. This is more relevant to Feasibility Assessment as Reliability Assessment models only one day.
	• Page 21, "PDR must start and end the day with the same quantity of stored gas," incorrectly assumes PDR will always be full.	• This will be tested.
	• Two reasons why page 12's hourly gas load profile assumption is problematic. 1), Using the proposed methodology, the proposed peak demand conditions would be expected to occur every year for the 1-in-35 condition and three times every year for the 1-in-10 condition. 2) Using recent data that may not be representative of future gas demand.	• The proposed approach is used to derive only the core demand profile shapes, which will then be stretched according to California Gas Report forecasts.
	• Assumed zonal capacities appear to be workable as a starting point. Commission should consider system resiliency, the need for contingencies, and perform	

	sensitivity analysis to determine how reductions to zonal capacity impacts the analysis. • Outage assumptions on page 16: Framework should not rely only historical outage data to forecast future outages. Changing regulatory requirements, advancements in technology, and efforts to upgrade and enhance the SoCalGas system will likely lead to more outages in the future.	• Analysis of outages will conclude what needs to be incorporated into the models. Advancements in technology should equally enable SoCalGas to enhance their system reliability, not decrease it.
	Feasibility Assessment • Perform feasibility assessment more efficiently by calculating a mass balance that derives month-end storage levels using CGR monthly demand forecasts, assumed/forecasted injection capabilities at our storage fields (taking into consideration planned and unplanned outages and facility injection capabilities) and assumed/forecasted flowing supplies that considers historical flowing supply highs and lows to develop a sensitivity analysis.	• Staff has added a mass balance if certain conditions are met.
	• Feasibility assessment does not consider injection capabilities of the fields; risk of overestimating amount of gas that could be injected.	• Injection capacity will be respected based on analysis of storage outages and storage inventory. The risk mentioned here is tied to the frequency of outages on the system and

		can result in underestimating the amount of gas, not only overestimating it.
	• The reliability assessment is assessing the system under stressed conditions, page 15 states "it is anticipated that the flowing supplies at the receipt points will be maximized to minimize the withdrawals from storage, including Aliso." In contrast, "the Feasibility Assessment is carried out under 'typical' or 'nominal' system conditions." Therefore, the feasibility assessment should reflect flowing gas supplies needed to support the "typical" or "nominal" demand condition plus those supplies that could be injected into storage. That level of flowing gas supplies is less (and likely far less) than the prescribed 85% for the Northern and Southern Zone and 100% for the Wheeler Ridge Zone.	• The word "nominal" has been removed. The outages analysis will incorporate both planned and unplanned outages into the zonal capacities based on historical data and maintenance schedules.
	• The Feasibility Assessment states that the stressed conditions in the Reliability Assessment are infrequent… and do not significantly impact the total storage volumes" over several months. Prudent planning requires planning for multiple peaks. Staff should analyze cold year and/or low hydro in Feasibility.	• Planning for multiple peaks is not considered and is stated in the assumptions.
	• Framework assumes 3,145 MMCFD of flowing supply will arrive at the zones, which is high and inconsistent	• We will look at data and analyze what is reasonable.

	with market realities. This past summer, customer demand ranged between 1,00 MMCFD to 3,000 MMCFD, with most months under 2,600 MMCFD. • Feasibility assessment assumes: customers will maximize flowing supplies, customers will purchase excess supply above their demand, and regularly monthly net injections • Commission should develop a forward looking and more comprehensive understanding of planned outages which includes compliance obligations, not only based on historical outage data.	
	Production Cost Model • At a high level, SoCalGas supports the Scenarios Framework's production cost model to the extent it proposes to understand economic dispatch of electric generation for an unconstrained system • It is not clear how the "constrained" or "minimum local generation" scenario will be modeled and used; provide more detail on purpose.	• We have provided more detail in the Scenarios Framework
	• The power flow modeling of LADWP and CAISO should be made available to parties to review and comment on to make sure that the power flow model is appropriately considering affordability and reliability and includes reasonable assumptions. This should include information on scenarios and assumptions that	• We will provide as much detail as we can under confidentiality limitations

	were modeled but not used or provided to the Commission.	
	• Does not include sufficient details on how the power flow modeling will occur. Whether the modeling will be done independently or in coordination – either between LADWP and CAISO or between LADWP, CAISO, and the Commission. • Indicate whether the power flow models will or are required to use a common set of database and assumptions. • Clarify what NERC reliability standard must be achieved • Explain why 5% LOLE is an appropriate level or how it was determined	• A flowchart has been included
	• Make information regarding the production cost model public – • Include Additional Explanation of How Daily Gas Usage Profiles Are Created	• Most PCM data is posted to the CPUC website here and we will post additional data as needed: http://www.cpuc.ca.gov/General.aspx?id=6442451973
	• How will hourly gas use for EG be accomplished, as stated on page 25?	• It will be gathered from the output of the PCM, from hourly dispatch reports.
	• What is meant by "1-in-10 Peak and 1-in-35 Extreme Peak operating conditions." It is unclear how the Scenarios Framework will apply these natural gas system design standards to electric generation.	• The economic modeling scope does not include those additions and has been stated in the summary of assumptions.

	Economic Modeling
	• Parties should be provided access to public data and code used as part of the analysis and a detailed description of any data and code used that is claimed to be confidential.
	• As SoCalGas has indicated in prior comments, the proposed economic modeling fails to adequately capture the economic benefits of Aliso Canyon and fails to account for the various direct and indirect economic impacts that reducing or eliminating Aliso Canyon would cause on California and surrounding states and core and noncore customers. Instead, the economic modeling appears primarily limited to core customer and electric generation impacts.
	• SoCalGas supports additional analysis, including:
	    ○ Additional costs to firm up supplies to meet core customers’ design day needs in lieu of Aliso Canyon
	    ○ Seasonal gas cost differentials
	    ○ Direct and indirect impacts on electricity prices associated with the interruption or lack of availability of Aliso Canyon
	    ○ General economic impacts
	    ○ Average price of gas impacts
	    ○ Costs associated with decreased reliability
		• Some of the listed costs are out of scope for this study and some are irrelevant. Regarding the impacts on electricity prices associated with the interruption or lack of availability of Aliso Canyon, the PCM will address that issue.
		• If more variation is observed in SoCalGas post Aliso incident, then we proceed the analysis to study the impact of storage on the gas price volatility.

	• On page 33, the sentence appears to be an incomplete sentence and does not indicate what the Scenarios Framework will do if more variation in SoCalGas.	
	• Relying on 2015-18 data sources is biased; recent weather has been mild, and Aliso Canyon was used differently than previously	• For the volatility analysis, we are considering using data before 2015.
	• The Scenarios Framework should indicate how this analysis will be used (will it be used in an attempt to understand the impact on core and noncore customer rates?) and how it will be factored into the determination of the benefits of Aliso Canyon and the future need for the facility.	• The analysis is assessing the source of volatility (if there is any). For, example is volatility due to weather, lack of storage, outages or other factors over time. The analysis is testing how significantly these factors impact the volatility in gas prices. The Analysis will look at periods pre- Aliso and post- Aliso.
	• DID assessment only works if one group (control group) is not impacted by an event. PG&E and its customers, however, are potentially impacted by constraints on Aliso Canyon. For example, as a result of restrictions on the use of Aliso Canyon, electric generation has been shifted from southern to northern California, which increases gas demand and prices in northern California	• Staff will attempt to surface these effects by evaluation of commodity costs for customers in similarly situated areas.
	• Choosing certain PG&E zip codes does not eliminate the differences between SoCalGas' and PG&E's systems and differences in costs driven by, for example, varying Commission-approved revenue requirements, and rates.	• We are attempting to control for these differences by analyzing commodity cost only, excluding other rate components, and analyzing similarly situated customers in zip codes where the two service areas overlap.

	• As an alternative, Commission staff can compare the commodity price paid by core customers. As another alternative, the Commission could examine future and historical consumer bill impacts, which includes estimating economic impacts on different classes of natural gas customers and aggregating these to derive annual cost of service increase and customer bill impact based on standard rate assumptions. • For the last economic analysis, the approach is complex, and it is not clear how these analyses will be translated into an impact on electricity prices.	• We have tightened our analysis to look at commodity costs only, not other rate components, due to concerns mentioned here of other confounding effects that we need to control for. The impact on electricity prices is found by assessing the implied heat rate over time to determine if there is a potential cause and effect between gas curtailment and generation dispatch and power prices. This analysis also will analyze the future implied heat rate by using the PCM data.
	• It is not clear if the implied market heat rate will also be calculated for future years; if it is, the calculation would be based on a predictive set of natural gas prices, but it is not clear how the Scenarios Framework is determining future PG&E CityGate and SoCalGas CityGate prices in future years.	• We will use information from the NAMGas model for future natural gas prices.
	• For the congestion rent assessment, SoCalGas is unclear how the prices in future years will be determined or how the results will be used.	• This analysis has been removed
	• The impact on the costs faced by electric consumers is better reflected by future wholesale power market price projections with and without Aliso Canyon.	• Agreed, staff will use PCM to capture these costs.

Name/Organization:	Comments	CPUC staff Responses:
Public Advocates Office Category: Consumer advocacy group	• Supports the Commission's plan to undertake hydraulic, economic, and production cost modeling effort. • On page 10, we question the reasonableness of curtailing electric gas load to zero under 1-in-35 and recommend that some level of EG load is met in 1-in-35. See San Diego Gas & Electric Company's and Southern California Gas Company's Tariffs 14 and 23, respectively. These tariffs allow for up to 60% of dispatched electric generation load to be curtailed during November through March and up to 40% of dispatched electric generation load to be curtailed from April through October.	• We evaluated Rule 23 and noticed there are multiple steps in the curtailment protocol, eventually leading to full curtailment of all electric generation. We added a test at the first 40% level of curtailment before assuming full curtailment under 1 in 35 conditions for the "Minimum Local Gas" Scenario.

APPENDIX C: Summary of Reply Comments

Name/Organization:	Comments
SoCalGas Category: Gas Utility	• Agrees with parties recommending hydraulic modeling of multiple outages on gas transmission system and/or storage fields. Energy Division (ED) should be mindful of the additional resources and time for additional modeling; Energy Division could model these stressed scenarios instead of some of the proposed average sendout condition scenarios. • SoCalGas supports Phase 2 modeling efforts to better understand the regional electric reliability impacts of reducing or eliminating the use of Aliso Canyon. • Top-down approach advocated by CAISO and CUE is not simple or straight-forward calculation. • Sierra Club and Environmental Defense Fund misstate the scope of Senate Bill 380 and the purpose of this proceeding. The purpose should not be closure of the facility, but an impartial and fact-based Commission decision on Aliso Canyon that supports reliability and affordability. • SoCalGas shares CAISO’s concerns regarding reliance on historical cost data. • Agrees with CUE that Phase 2 should include severely stressed scenarios. • Agrees with CUE that modeling should consider impacts reductions to Aliso Canyon have on EGs and reduced system flexibility. • Agrees with CUE that economic modeling needs to be clearer, broader, and more robust. • Agrees with TURN that scaling demand may not be appropriate across all seasons and customer classes. Energy Division should consider ramping needs of end users. • Agrees with TURN that higher amounts of renewables may increase the need for electric ramping products, as highlighted in the CCST Study. • Magnum supplies would not be as effective as locally stored supplies to meet local demand • Najm’s comments about Aliso’s role and use are incorrect.

	• The hydraulic modeling data may contain confidential information, market sensitive information, or customer information that should not be shared. • Najm's suggestion that hourly usage data of all core customers can be simply calculated is not correct. • Najm's suggested receipt point utilization is unreasonably high and does not reflect actual experience on the system. • None of the reductions identified by Sierra Club are certain to occur; they are all potential or contingent. • SoCalGas cannot reasonably forecast how achieving SB 100 targets will impact the California Gas Report figures since California has not put in a place a plan to accomplish the SB 100 targets. • EDF incorrectly states that regional power plants receive gas without paying for the service. • EDF suggests changing the natural gas market rules in modeling; but, modeling should be done assuming existing market rules. • The current regulatory requirements and realities should be modeled, not potential or unauthorized changes.
Name/Organization: California Independent System Operator (CAISO) Category: Balancing authority	Comments: • CAISO intends to use its existing Local Capacity Technical (LCT) Study process to determine minimum electric generation levels in its Southern California balancing area. • The LCT Study will be provided to the Commission as inputs to the Production Cost Model. • CAISO clarified that their LCT Study will meet NERC and CAISO standards, as well as Local Reliability Criteria • CAISO clarified that they will determine minimum generation requirements for those Local Capacity Areas within CAISO's balancing area, which does not include LADWP.
Name/Organization: Sierra Club	Comments:

Category: Environmental organization	• A gradual phase-out of existing gas infrastructure is needed; Commission needs to facilitate electrification in the Aliso area to increase system resiliency and enable the permanent closure of the Aliso facility • A study by E3 for the California Energy Commission found that transitioning to low-carbon electricity for heating offers the most promising path for achieving Greenhouse Gas reduction targets in the least costly manner • The CEC and ARB have identified the importance of building electrification in meeting California's climate goals; focusing on reducing gas demand from Aliso is an opportunity for the Commission to do so.

(End of Attachment)