Decision 22-07-002 July 14, 2022

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and perform Long-Term Gas System Planning.	Rulemaking 20-01-007

DECISION ON TRACK 1A AND 1B ISSUES

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DECISION ON TRACK 1A AND 1B ISSUES

Summary

In this decision, we resolve issues related to questions from Track 1A and 1B of the April 23, 2020 Assigned Commissioner's Scoping Memo and Ruling. Specifically, we address questions 1 through 5 of Track 1A and questions 1 and 2 of Track 1B. This decision additionally requires Southern California Gas Company and Pacific Gas and Electric Company to maintain adequate backbone capacity to meet the average day in a 1-in-10 cold and dry year standard established by Commission Decision 06-09-039. This decision establishes a framework for a citation program when a utility fails to maintain adequate backbone capacity as set forth in Appendix A.

This proceeding remains open to address outstanding issues in Track 2.

1. Background

The Commission initiated this proceeding on January 16, 2020, to create a long-term planning framework for the state's natural gas system in response to California's climate goals and in recognition of the rapid development of renewable energy sources that will, over time, lessen the state's dependence on fossil gas for both businesses and consumers. After receiving opening comments from twenty-one parties[1] and reply comments from fourteen parties,[2] then-assigned Commissioner Randolph issued a Scoping Ruling. The Scoping Ruling divided the proceeding into two separate tracks, with a Commission decision to follow each track. The first track includes two sub-tracks, Track 1A and Track 1B. Track 1A addresses reliability standards, and Track 1B examines potential regulatory changes needed to improve the coordination between gas utilities and gas-fired electric generators.

On July 7, 2020 and July 21, 2020 Energy Division staff held workshops on the scope of issues outlined in Tracks 1A and 1B of this proceeding. The purpose of these workshops was to address the specific questions outlined in the scoping memo and ruling, gain a common understanding of the issues, gather information and facts, seek input from stakeholders, and identify solutions.

On July 31, 2020 the assigned Administrative Law Judge (ALJ) issued a ruling directing parties to comment on fourteen questions set out in the ruling.[3]

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[1] Opening Comments were received from The Utility Reform Network (TURN), Southern California Generation Coalition (SCGC), Middle River Power, LLC (MRP), Sacramento Municipal Utility District (SMUD), Coalition of California Utility Employees (CCUE), Environmental Defense Fund (EDF), Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), Southwest Gas Corporation (Southwest Gas), California Independent Systems Operator Corporation (CAISO), Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) jointly, Independent Energy Producers Association (IEPA), Sierra Club, Natural Resources Defense Council (NRDC), Vistra Energy Corporation (Vistra), Utility Consumers' Action Network (UCAN), Center for Energy Efficiency and Renewable Technologies (CEERT), Calpine Corporation (Calpine), California Hydrogen Business Council (CHBC), and Wild Tree Foundation (Wild Tree).

[2] Reply Comments were received from Aera Energy LLC, California Resources Corporation, Chevron U.S.A. Inc., ConocoPhillips, PBF Holding Company, Phillips 66 Company, and Tesoro Refining & Marketing Company LLC. (collectively, Indicated Shippers), Sierra Club, NRDC, California Environmental Justice Alliance (CEJA), UCAN, CHBC, PG&E, SWGC, SCE, SoCalGas and SDG&E (jointly), TURN, SCGC, and the Public Advocates Office (Cal Advocates).

[3] Opening comments were received from IEPA, CAISO, CEERT, PG&E, SBUA, EDF, UCAN, SCE, Electrochaea GmbH (Electrochaea), Protect Our Communities Foundation (PCF), The

On October 2, 2020, the ALJ issued a ruling attaching the Workshop Report and Staff Recommendations (Workshop Report) and seeking comments thereon. The ruling also directed specific parties to provide supplemental information. As part of this requirement, both PG&E and SoCalGas were directed to submit formal analyses outlining a proposal for a Renewable Balancing Tariff in their respective regions and its associated costs. The ruling also entered into the record an Energy Division Staff White Paper on "California Gas Utility Reliability: Definition, Standards, and Measures."[4]

On January 8, 2021, SoCalGas and PG&E filed Renewable Balancing Tariff proposals in response to the ALJ's October 2 ruling.[5]

On February 26, 2021, the ALJ issued a ruling seeking comments on a series of questions contained in an attachment to the ruling.[6]

Greenlining Institute (Greenlining), CEJA, Calpine, Californians for Green Nuclear Power, Inc. (CGNP), Southwest Gas, MRP, Cal Advocates, SCGC, SDG&E, SoCalGas, Indicated Shippers, TURN, the Department of Market Monitoring of the California Independent System Operator Corporation (CAISO Monitor), and the Western States Petroleum Association (WSPA).

[4] Opening comments on the Workshop Report were received from CHBC, EDF, TURN, Cal Advocates, MRP, PG&E, CEERT, UCAN, Greenlining, CDGA, Green Hydrogen Council (GHC), SMUD, IEPA, CAISO, Indicated Shippers, SCGC, SoCalGas, SDG&E, Electrochaea, SCE, PCF, Central Valley Gas Storage, LLC (CVGS), and SBUA. Reply comments were received from SCE, Indicated Shippers, Greenlining, CEJA, MRP, Calpine, UCAN, CEERT, CHBC, SoCalGas, SDG&E, CAISO, Small Business Utility Advocates (SBUA), PG&E, WSPA, TURN, PCF, United Energy Trading, LLC, School Project for Utility Rate Reduction (UET/School), EDF, Vistra, and SCGC.

[5] Opening comments on the proposals were received from TURN, MRP, Indicated Shippers, PCF, SCGC, SCE, and SBUA. Reply comments were received from SBUA, TGI, CEJA, SCE, Calpine, PG&E, Indicated Shippers, SCGC, PCF, SDG&E, SoCalGas, UCAN, and EDF.

[6] Comments on the ruling were received from Indicated Shippers, TGI, CEJA, SWGC, EDF, PG&E, UCAN, TURN, SCE, SDG&E, SoCalGas, Shell Energy North America (US), L.P. (Shell), MRP, CAISO, SCGC, and CEERT.

On June 25, 2021, the ALJ issued a ruling seeking comments on a staff proposal for a penalty for a utility's sustained failure to meet design standards.[7]

On September 23, 2021, the ALJ issued a ruling denying motions for evidentiary hearings and granting motions for the filing of briefs on all Track 1 issues. Opening briefs were received from TURN, Cal Advocates, EDF, TGI, CEJA, Indicated Shippers, SCGC, PCF, PG&E, SDG&E, and SoCalGas. Reply briefs were received from PG&E, TURN, SCGC, PCF, SCE, SDG&E, SoCalGas, UCAN and Indicated Shippers.

2. Issues Before the Commission

In this decision, we resolve issues related to questions 1 through 5 of Track 1A and questions 1 and 2 of Track 1B of the April 23, 2020 Scoping Memo.

3. Track 1A: Reliability Standards

This first discussion section focuses on questions 1a and 1b in the Scoping Memo. First, do PG&E and SoCalGas have the requisite gas transmission pipeline and storage capacity to meet the demand for an average day in a one-in-ten cold and dry-hydroelectric year for their respective backbone gas transmission systems and peak day demand for their combined backbone gas transmission and gas storage systems? Second, do PG&E and SoCalGas have the requisite gas transmission pipeline and storage capacity to meet the local transmission standards adopted in Decision (D.) 06-09-039?

In D.06-09-039, the Commission established backbone transmission and peak day standards for PG&E and SoCalGas.[8] The backbone transmission

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[7] Opening comments were received from UCAN, TURN, EDF, PG&E, SoCalGas, SDG&E, Indicated Shippers, PCF, SCGC, and SBUA. Reply comments were received from UCAN, EDF, SDG&E, SoCalGas, PCF, SCGC, Indicated Shippers, and PG&E.

[8] D.06-09-039, Ordering Paragraphs (OPs) 1 and 2.

standard is to be met using pipelines only, and it is the same for both utilities. Both PG&E and SoCalGas are required to "plan and maintain intrastate natural gas backbone transmission systems sufficient to serve all system demand on an average day in a one-in-ten cold and dry-hydroelectric year."

The Commission directed PG&E and SoCalGas to use both their backbone transmission and storage systems to meet their peak day standards. However, D.06-09-039 based each utility's peak day standard on its existing local transmission system standard. Thus, the peak day standards for the two utilities differ. For PG&E, the peak day design standard requires that it serve all customers on a 1-in-2 winter cold day and core customers only on an abnormal 1-in-90 winter peak day.[9] For SoCalGas, the peak day design standard requires that it serve all customers on a 1-in-10 peak day and core customers only on a 1-in-35 extreme peak day.[10] The table below shows the local transmission standards adopted in D.06-09-039.

Local Transmission Standards[11]

	PG&E		SoCalGas	
Standard	1-in-90 Abnormal Peak Day	1-in-2 Cold Winter Day	1-in-35 Extreme Peak Day	1-in-10 Cold Day[12]
Customer Class Served	Core	Core + Noncore	Core	Core + Noncore

The California Gas Report, which is published biannually by the California gas utilities in consultation with the California Energy Commission (CEC) and

[9] 2020 California Gas Report, at 84-85.

[10] D.02-11-073, OP 10.

[11] PG&E and SoCalGas use different terminology to describe the standards.

[12] The California Gas Report uses the term "cold day" for what we say is a "peak day."

the Commission, includes annual forecasts for some of the standards approved in D.06-09-039.[13] The July 7, 2020 Track 1A workshop was held in the weeks before the 2020 California Gas Report was issued on August 24, 2020. Thus, speakers referenced demand figures for the year 2020 based on either preliminary 2020 Gas Report calculations (PG&E) or the 2018 California Gas Report (SoCalGas). However, in this decision, we will refer to the more up-to-date figures in the 2020 California Gas Report. The table below shows the peak day demand forecast and the cold year forecast for each utility. As discussed above, PG&E's Cold Day Standard is that it meets all customer demand on the coldest day in two years. The table below does not include a value for the PG&E Cold Day Standard because PG&E does not historically include that number in the California Gas Report. SoCalGas' Peak Day Standard is to supply all customer demand on the coldest day in 10 years. That number (4,983 MMcfd) is included in the table.

2020 California Gas Report Forecasted Demand (MMcfd)[14]

Standard	PG&E	SoCalGas
Backbone	2,079	2,540
Cold/Peak Day (All Customers)	n/a	4,983
Peak Day (Core Customers)	3,031	3,460

[13] The cold year forecasts in the California Gas Report do not exactly match the standards approved in D.06-09-039. PG&E includes a forecast for its Abnormal Peak Day standard but not for its 1-in-2 Cold Winter Day standard. PG&E also includes tables for a "High Demand Year (1-in-10 Cold Year)" but does not specify whether the year is both cold *and* dry (at 90-91). SoCalGas includes forecasts for both its 1-in-10- and 1-in-35-day standards, but its tables for a "Cold Temperature Year (1-in-35 Cold Year Event) and Dry Hydro Year" are for a colder year than required by the decision (at 146-47).

[14] Million cubic feet per day.

PG&E and SoCalGas presented on their current system capabilities at the July 7, 2020 workshop. PG&E indicated that it has a total backbone transmission system capacity of 3,055 million cubic feet per day (MMcfd) and that it can meet average demand during a 1-in-10 cold and dry hydroelectric year using only its backbone transmission system.

PG&E stated that it owns several storage fields and relies on independent storage providers—including Wild Goose, Lodi, Central Valley, and Gill Ranch storage fields—to meet customer demand. In its presentation, PG&E stated that it can meet its peak day standards using transmission and storage.

At the workshop, SoCalGas indicated that it can meet its backbone transmission standard. Its then-current backbone capacity of 2,965 MMcfd exceeds the average day in a cold and dry year demand forecast of 2,540 MMcfd.[15]

In its presentation, SoCalGas said that it had 4,130 MMcfd of combined pipeline and storage capacity, and thus was able to meet its 1-in-35 peak day standard, which serves only core customers.[16] However, it was not then able to meet its 1-in-10 peak day standard of 4,983 MMcfd to serve both core and noncore customers. The utility cited reduced storage withdrawal capacity, backbone pipeline outages, and operating limitations as reasons why it could not meet the standard. SoCalGas also stated that in the operating years 2025-26, 2030-31, 2035-36, it would have sufficient capacity to meet its 1-in-10-year cold day standard assuming that its transmission pipelines and storage fields are

[15] Track 1A and 1B Workshop Report and Staff Recommendations, at 7: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M348/K035/348035848.PDF.

[16] *Id.* SoCalGas stated that it had 2,965 MMcfd of interstate pipeline capacity, 60 MMcfd of California gas production, and 1,105 MMcfd of December through January storage withdrawal capacity (Slide 61).

restored to their former capacities (e.g., the Northern System returns to its nominal capacity of 1,590 MMcfd).

In the Workshop Report issued on October 2, 2020 Energy Division Staff (Staff) concluded that PG&E has the requisite gas transmission pipeline and storage capacity to meet average day demand in a 1-in-10 cold and dry-hydroelectric year and their abnormal peak day demand as forecasted in the 2020 California Gas Report. SoCalGas has the requisite capacity to meet demand for an average day in a 1-in-10 cold and dry-hydroelectric year. Staff concluded that SoCalGas can meet the 2020 1-in-35 extreme peak day demand of 3,490 MMcfd but not the 1-in-10 cold day demand.

3.1. How should the Commission respond to a gas utility's sustained failure to meet minimum transmission system design standards?

Several parties weighed in on this issue at the July 7, 2020 workshop, specifically focusing on failures to meet minimum transmission system design standards caused by pipeline breaks or other events requiring the utility to make physical repairs to the system. Indicated Shippers suggested that utilities should be required to share in the cost of such repairs, or the Commission should reduce the utility's return on equity (ROE). TURN suggested that utility shareholders should absorb a percentage of the cost of repairs on a graduated scale, with the percentage borne by shareholders increasing with the length of time that the design standard is not met.

In response to the July 31, 2020 Ruling Seeking Comments related to follow-up questions after the workshops, parties provided comments on how the Commission could respond to a utility's sustained failure to meet the required design standards because of the need to make physical repairs. TURN reiterated the suggestions it made during the July 7, 2020 workshop and advised against reducing a utility's ROE, asserting that such a mechanism could encourage more expensive repairs that may not be necessary.[17] Indicated Shippers suggested a sliding scale methodology to evaluate whether shareholders should be held responsible for future pipeline or other infrastructure outages. Specifically, Indicated Shippers suggested a sliding scale of shareholder contribution to the cost of repairs based upon actual costs and length of the outage and a sliding scale of basis point reductions to ROE.[18] EDF agreed that shareholders should share the responsibility for repair costs but stated that revising a utility's ROE for failure to maintain minimum design standards is not appropriate. EDF maintained that changes to a utility's ROE should only be considered in cost of capital proceedings.[19]

In the Workshop Report, Staff agreed with TURN that there should be consequences for a utility's failure to meet the design standards but also noted that there may be challenges with permitting and construction in remote, protected areas where many of the transmission pipelines are located. For this reason, Staff recommends using the nine-month criterion in Pub. Util. Code § 455.5 as a guideline for determining the duration after which shareholders begin to absorb a percentage of the cost of repairs.[20]

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[17] TURN Comments at 6 (August 14, 2020).

[18] Indicated Shippers Response at 7. (August 14, 2020)

[19] EDF Comments at 3. (August 14, 2020)

[20] *See* Workshop Report and Staff Recommendations, at 35, available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M348/K035/348035848.PDF. Pub. Util. Code § 455.5(a) states. "In establishing rates for any electrical, gas, heat, or water corporation, the commission may eliminate consideration of the value of any portion of any electric, gas, heat, or water generation or production facility which, after having been placed in service, remains out of service for nine or more consecutive months, and may disallow any expenses related to that facility."

SCGC, PCF, and UCAN oppose Staff's recommendation to use the nine-month criterion as a guideline for the period before the penalty goes into effect.[21] EDF and TURN support the use of the nine-month criterion.

TURN disagreed with Staff's recommendation to set a penalty regime for a standard that includes both pipeline and storage assets, arguing that "there needs to be a minimum amount of intrastate backbone pipeline capacity available on an annual basis in order to fill the storage during periods of lower demand."[22] TURN argued there may be instances where the utility has enough storage supply to meet peak day demand but then is unable to refill that storage for the upcoming winter due to limited pipeline capacity.

3.1.1. Summary of June 25, 2021 Staff Proposal (Nine-Month Penalty)

On June 25, 2021, Staff issued a Staff Proposal proposing a nine-month penalty that defined which standard would be addressed, the penalty structure, utility reporting requirements, how the citation program would be enforced, and a force majeure clause. The June 25, 2021 Staff Proposal included the following elements:

> <u>Minimum Design Standard</u>: The utilities should be required to maintain adequate backbone capacity to meet the average day in a 1-in-10 cold and dry year standard established by D.06-09-039. The annual backbone capacity standard would serve as a floor below which backbone pipeline capacity should not fall. By maintaining adequate backbone capacity, a utility would be better positioned to fill storage to help meet winter peak demand.
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> <u>Penalty Structure</u>: (a) The Commission should impose a daily penalty of $50,000 on a utility that has been out of compliance

[21] SCGC Comments at 11; UCAN Comments at 3; PCF Comments at 15. (November 2, 2020)

[22] TURN Comments at 3. (November 2, 2020)

with the proposed backbone capacity standard for more than nine months; (b) the daily penalty should increase to $75,000 if the utility has been out of compliance for an additional three months; and (c) the penalty continues to accrue until the utility is in compliance as verified by Energy Division staff.

Reporting Requirement: The utilities should add information about any changes impacting their ability to meet the backbone capacity standard to the existing advice letters on slack capacity that they are required to file as per D.06-09-039. These advice letters should be made biannual rather than biennial and specify the actual operating capacities of their backbone transmission lines/zonal areas or paths as opposed to the nominal capacities. The utilities should separately notify Energy Division in writing on the first day they fail to meet the nine-month backbone capacity standard. Staff will verify whether the actual operating capacities reported by the utilities in the biannual advice letters are accurate by comparing the reported figures with available capacities shown on SoCalGas' Envoy and PG&E's Pipe Ranger websites. Further, if staff is unable to verify the information contained in a biannual advice letter and staff's calculations indicate that the utility may not be meeting the standard, staff will draft a resolution proposing a revised capacity level.

Citation Program: If Energy Division determines that a utility is out of compliance with the required backbone capacity standard, it will refer the matter to the Commission's Utility Enforcement Branch, which would have the authority to issue citations and levy fines in accordance with the penalty structure described in this decision.

Force Majeure Clause: If a force majeure event prevents the utility from providing backbone capacity consistent with a 1-in-10 cold and dry year standard for nine months or longer, then it would not be considered to be in violation of the standard. Staff recommends adoption of the following definition:

Force Majeure Event:

An act of a governmental authority in the exercise of its jurisdiction or the occurrence of a declared disaster or state of emergency by federal or state authorities. The Utility shall use all reasonable efforts to remedy such events or conditions and to remove the cause of same in an adequate manner and with reasonable dispatch. The occurrence of high demand for gas service due to weather conditions shall not constitute a force majeure event.

3.1.2. Party Positions on June 25, 2021 Staff Proposal

Parties supported the Staff Proposal to varying degrees and offered modifications. SoCalGas and SDG&E filing jointly, EDF, TURN, SCGC, PCF, UCAN, and SBUA generally supported use of the 1-in-10 cold and dry year backbone capacity as the minimum design standard. SoCalGas and SDG&E filing jointly and PG&E argued that penalties should not be imposed automatically without a finding of fault. TURN, Indicated Shippers, SCGC, PCF, and UCAN suggested steeper penalties than those proposed by Staff. PG&E and SBUA suggested that penalties should rise more slowly. SCGC and PCF contended that there should not be a nine-month delay in the imposition of penalties. Similarly, SBUA argued that penalties should apply sooner than nine months. SCGC, PCF, TURN, and Indicated Shippers assert that penalty dollars should go back to ratepayers rather than the state's General Fund. TURN contends that "this approach would ensure that those who suffer harm as a result of a utility's failure to meet the backbone pipeline availability standard are the ones who benefit from the remedy."[23] UCAN noted that the Commission must direct monies it receives from penalties or fines to the state's General Fund.

SoCalGas and SDG&E filing jointly, PG&E, SCGC, and PCF offered revisions to the force majeure clause recommended by Staff. TURN requested

[23] TURN Reply Brief (Track 1 Issues) at 6. (October 29, 2021)

that Staff track utility compliance with the standard by calculating the nine-month rolling average of daily transmission capacity and comparing it to the 1-in-10 cold and dry year standard. EDF requested that Staff notice the proceeding's service list of any citations issued under the program.

In response to party comments, we address what modifications should be made to the Staff Proposal below.

3.1.3. Modified Nine-Month Penalty

First, we address how Staff should determine compliance with the standard. The Proposed Decision agreed with TURN's suggestion that we track compliance by calculating the nine-month rolling average of available capacity in Cycle 1 of the Gas Day.[24,25] SoCalGas and SDG&E filing jointly supported that approach because "it would give the utility credit for days when the available capacity was in excess of the standard and would continue the nine-month "clock" if the standard was not met for only one or a few days within that period."[26] However, after considering all the comments on the proposed decision, we conclude that it is overly complex and raises questions about timing and implementation that can be avoided by replacing the nine-month rolling average of backbone capacity with the utility's daily available backbone capacity as the appropriate standard. Utilities shall, via a Tier 1 Advice Letter, inform the Commission's Energy Division and the R.20-01-007 service list on the first day that their available backbone capacity falls below the 1-in-10 cold and dry year

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[24] TURN Opening Comments on Staff Proposal at 4. (July 30, 2021)

[25] The Gas Day is divided into windows of time during which gas shippers can make nominations, or request that gas deliveries be made on their behalf, on a pipeline system. Cycle 1 (also known as Timely Cycle) nominations must be made before 11:00 a.m. on the day before the gas is delivered.

[26] SoCalGas/SDG&E Joint Opening Brief at 9. (October 15, 2021)

standard established by D.06-09-039 calculated according to the process described in Appendix A, Attachment 1. Utilities must report their available backbone capacity in both million cubic feet per day (MMcfd) and dekatherms (Dth) in this Tier 1 advice letter.

We direct the Commission's Utility Enforcement Branch (UEB) to propose a citation program for failure to meet minimum design standards established by D.06-09-039 consistent with Resolution ALJ-377 and this decision and as set forth in Appendix A.

If the utility has not restored backbone capacity above the minimum standard within nine months, Energy Division shall refer the matter for investigation to UEB to determine appropriate action. UEB will decide whether to issue a citation. Energy Division will track compliance with the standard from the effective date of this decision on a going-forward basis, rather than looking back at prior utility action.

Next, we address modifications to the citation program proposed by Staff. As UCAN noted, the recommendations made by parties to direct monies collected through this citation program to ratepayers cannot be adopted, because the Commission does not have the power to direct fines imposed through a citation program to ratepayers. We confirm that penalties borne by shareholders are not considered a recoverable expense in future advice letter filings in addition to general rate case filings. UEB currently posts information on citations issued on the Commission's website.[27] Accordingly, we decline to adopt EDF's proposal that Staff notify the R.20-01-007 service list of any citations issued under the citation program discussed here. Lastly, we find it reasonable to modify the

[27] https://www.cpuc.ca.gov/regulatory-services/enforcement-and-citations/utility-enforcement-branch/energy-citation-programs.

force majeure clause to include certain factors beyond the utility's reasonable control, whether or not they are the subject of a government declaration.

With these modifications, the Staff Proposal strikes the right balance between establishing penalties for a utility's failure to meet minimum design standards and providing the utility with a reasonable amount of time to address any maintenance outages that may hinder its ability to meet the minimum design standard. The penalty mechanism is intended to provide sufficient deterrence to avoid violation of the required standard because of the significant potential impact of failure to meet the minimum design standard on customers and to incentivize recovery as quickly as possible.[28] Moreover, the citation program will afford the utilities due process to review the alleged violation. Utilities may raise concerns with the level of penalties imposed in any appeal of a UEB citation, including raising any need to consider mitigating factors. The Commission will consider all requirements, including due process, in considering UEB's proposed resolution adopting this citation program. We summarize the minimum design standard, penalty structure, reporting requirements, processes for referrals to UEB, and force majeure standards:

1. <u>Minimum Design Standard</u>: PG&E and SoCalGas should be required to maintain adequate backbone capacity to meet the average day in a 1-in-10 cold and dry year standard established by D.06-09-039. This standard will serve as a floor below which the utility's daily available backbone capacity should not fall.
2. <u>Penalty Structure</u>: If a utility's daily available backbone capacity calculated in Cycle 1 of the Gas Day falls below the average day in a 1-in-10 cold and dry year standard established by D.06-09-039, the utility will be subject to a penalty of $50,000 per day for each day beyond nine

[28] Pub. Util. Code Sections 2107 and 2108.

months that it remains out of compliance. If the utility remains out of compliance for twelve months or more, the daily penalty will increase to $75,000 for each day beyond twelve months that it remains out of compliance.

3. Reporting Requirement: The utilities must report biannually (on April 15 and October 15) on any changes impacting their ability to meet the minimum design standard in the Tier 2 advice letters on slack capacity that they are required to file by D.06-09-039. These Tier 2 advice letters should be served on the R.20-01-007 service list and must specify the actual—not the nominal—average Cycle 1 operating capacities of the utilities' backbone transmission pipelines by zonal area or path over the previous nine-month period in both million cubic feet per day (MMcfd) and dekatherms (Dth) according to the formulas described in Appendix A, Attachment 1.

   The utilities must separately notify Energy Division and the R.20-01-007 service list via a Tier 1 Advice Letter on the first day the backbone transmission capacity fails to meet the minimum design standard as described in Appendix A, Attachment 1. Utilities must report their actual available backbone capacity in both million cubic feet per day (MMcfd) and dekatherms (Dth) in this Tier 1 advice letter. Staff will verify whether the actual operating capacities reported by the utilities in the biannual advice letters are accurate by comparing the reported figures with available capacities shown on SoCalGas' Envoy and PG&E's Pipe Ranger websites.

   If staff is unable to verify the information contained in an advice letter and staff's calculations indicate that the utility is not meeting the minimum design standard, staff will draft a resolution proposing a revised capacity level reflecting figures derived from SoCalGas' Envoy or PG&E's Pipe Ranger websites as described in Appendix A, Attachment 1.

4. Referrals to UEB Under Future Citation Program: If Energy Division determines that a utility is out of compliance with the minimum design standard for over

nine months after it first was out of compliance, it will refer the matter for investigation to the Commission's Utility Enforcement Branch to determine appropriate action, with service of the referral on the R.20-01-007 service list. The Utility Enforcement Branch is directed to issue citations and levy fines in accordance with Resolution ALJ-377 and the penalty structure described in this decision. Penalties are borne by shareholders and are not a recoverable expense in future rate case or advice letter filings.

5. Force Majeure Clause: A utility will not be considered to be out of compliance if a force majeure event prevents it from meeting the minimum design standard. The utility shall use all reasonable efforts to mitigate the consequences of force majeure events with reasonable dispatch. The following definition of a force majeure event shall apply:

Force Majeure Event:

> *An event beyond the reasonable control of the Utility including, without limitation, an* act of a governmental authority in the exercise of its jurisdiction; a state of emergency declared by federal or state authorities*; natural disasters such as fires, floods and earthquakes; strikes; and civil disorders.* The occurrence of high demand for gas service due to weather conditions shall not constitute a force majeure event.

The statutory system for penalties set forth in Public Utilities Code sections 2107 and 2108 provides the Commission broad authority to impose penalties ranging from $500 to $100,000 for each violation. The Commission's penalty assessment methodology set forth in D.98-12-075 and Resolution M-4846 informs the penalty structure of citation programs.

The purpose of the citation program described above is to promote utility compliance with the minimum design standard to ensure reliable gas service to core and non-core gas customers. Non-compliance with this standard can have serious reliability impacts on gas customers. In the case of core customers, this can potentially have negative health and safety implications.[29] The costs of potential gas service curtailment and gas price spikes arising from constrained system conditions can also be very significant.[30]

Given the significant potential customer harm arising from non-compliance, potentially in the hundreds of millions of dollars, the need to sufficiently deter non-compliance with the standard, and to incentivize recovery as quickly as possible, we conclude that the penalty for non-compliance with the minimum design standard for nine months or longer should be $50,000 for each day thereafter that it remains out of compliance. The penalty for non-compliance with the minimum design for 12 months or longer should be set at $75,000 for each day thereafter that it remains out of compliance, and will continue to accrue until the date on which the utility is back in compliance.

This penalty structure takes utilities' actions to comply into account as penalties are only triggered after the utility has been out of compliance for a period of nine months, thereby providing the utility a significant length of time to come into compliance. It also takes into account other mitigating circumstances as defined in the force majeure provision.

We expect that a $50,000 daily penalty after nine months of sustained non-compliance is large enough, in most cases, to provide an incentive for the utility to remedy non-compliance in a timely manner. However, if the utility fails to come into compliance for an additional three months, then a higher penalty is warranted in order to increase the incentive to comply. Accordingly, the penalty amount will increase to $75,000 after 12 months of non-compliance. Ensuring

[29] UCAN Reply comments August 13, 2021 at 1

[30] UCAN Comments on Staff Proposal July 30, 2021 at 1.

compliance with the minimum design standard is critical. We believe that these penalty amounts will provide a sufficient incentive for compliance and deter non-compliance. We have also considered the financial resources of the utilities covered by this citation program in establishing the penalty amounts. These entities are very large corporations with ample resources to operate in compliance with the minimum design standard. The penalty amounts established here are commensurate with their financial resources.

3.2. Are the existing natural gas reliability standards for infrastructure and supply still adequate? If not, how should they be changed?

The July 31, 2020 Ruling Seeking Comments sought input from TURN, Cal Advocates, and other consumer advocate groups regarding the potential need to change existing reliability standards given the high gas and electricity costs incurred in 2017 and 2018 due to volatile market conditions and slim margins between gas supply and demand.[31] Cal Advocates asserted that the reliability standards do not need to be changed at this time.[32] Compared to the energy crisis of 2000, Cal Advocates explained that California is in a much better position today to shift or reduce peak demand.[33] TURN initially took the position that the existing standards are adequate and cited pipeline outages and lack of access to Aliso Canyon as reasons for market volatility.[34] The Indicated Shippers, UCAN, SCGC, and PCF also advised against changing the current reliability standards.

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[31] Parties also submitted opening and reply briefs on this issue on October 15, 2021 and November 1, 2021, respectively.

[32] Cal Advocates Comments (Response to Assigned Administrative Law Judge's Ruling Seeking Comments) at 1.

[33] *Id*. at 4.

[34] TURN Comments (In Response to Questions in July 31, 2020 ALJ Ruling) at 3.

In contrast, the Justice Parties argued that "the Commission should reject excessive reliability metrics like PG&E's 1-in-90 abnormal peak day" standard.[35] PG&E strongly opposed changing most of the reliability standards but stated that "a 1-in-40 year core standard may represent a reasonable balance of costs and reliability."[36] In its reply brief, TURN supported a 1-in-40 Abnormal Peak Day standard for PG&E's core customers, stating that the change in standard could also be made in Gas Transmission and Storage Cost Allocation and Rate Design (GT&S CARD) proceeding, A.21-09-018.[37]

TURN and the Justice Parties have not provided a sound basis to support their argument that a 1-in-40 years standard would be more appropriate than PG&E's current 1-in-90 abnormal peak day standard. Given this, and party support for retaining the current standards, we do not see a need to change existing infrastructure design standards for PG&E or SoCalGas at this time.

We now turn our attention to Staff's recommendation to adopt a definition of reliability. At the July 7, 2020 workshop, both PG&E and Energy Division recommended the adoption of a reliability definition that would guide the creation of "clear and concise minimum design standards." Staff suggested in the Workshop Report that any adopted reliability definition should consider the increasingly intertwined gas and electric markets, citing the critical nature of natural gas during times of low renewable energy generation.[38] Staff recommended adopting the following definition:

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[35] Justice Parties Opening Brief at 8.

[36] PG&E Opening Brief at 8-9.

[37] TURN Reply Brief at 4-5.

[38] Workshop Report at 37.

> *Gas Reliability is a measure of the gas system's capacity and ability to deliver uninterrupted service. It represents the ability to supply gas and the capacity to transport it in amounts sufficient to meet customer demand.*[39]

There was consensus among parties that a reliability definition should be adopted. In response, parties offered modifications to Staff's proposed definition. PG&E suggested modifying Staff's proposed definition so that it specifically refers to "gas customer service reliability" instead of "gas reliability."[40] SCGC recommended Staff modify the proposed definition of "reliability" so that (it) applies to a gas system's capacity without reference to supply, which is the responsibility of customers, energy service providers, and the utilities' core gas procurement departments.[41] TURN suggested omitting reference to "supply," noting that it is not the responsibility of the utility to supply gas but rather to deliver gas received at the California border.[42] UCAN also supported omitting mention of *supply* in the definition.

We acknowledge that Commission-jurisdictional gas utilities are not responsible for procuring gas for all customers. With a few relatively minor exceptions, it is the customers of SoCalGas and PG&E or the utilities' core procurement divisions, which are separated by a firewall from their other divisions, who must procure and schedule delivery of gas onto the system. Thus, we find TURN, UCAN, and SCGC's request to omit mention of *supply* from

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[39] *Id*.

[40] PG&E Opening Comments (in Response to Assigned Administrative Law Judge's Ruling Issuing Workshop Report and Staff Recommendations, Seeking Comments, and Modifying Procedural Schedule) at 12.

[41] SCGC Comments at 3.

[42] TURN Comments (October 2, 2020 Staff Workshop Report) at 8.

Staff's proposed gas reliability definition to be reasonable. Accordingly, we will adopt the following reliability definition:

> *Gas reliability is a measure of the gas system's capacity and ability to deliver uninterrupted service. It consists of adequate physical and operational capacity to transport gas in amounts sufficient to meet customer demand.*

Lastly, we address the question of supply standards. In D.04-09-022, the Commission established supply standards, or "capacity planning ranges," which are target ranges that the utilities are required to meet to ensure sufficient interstate gas supply and storage capacity portfolios for core customers.[43] In doing so, the Commission intended to ensure that California did not face natural gas supply shortages for core customers.

It is important to note that SoCalGas' Gas Acquisition Department and PG&E's Core Gas Supply Department are responsible for procuring gas on behalf of core customers, which are primarily made up of residential and small business customers. As noted above, there is a firewall between SoCalGas' Gas Acquisition Department and the SoCalGas Gas System Operator and PG&E's Core Gas Supply Department and PG&E's Gas System Operator.

For SoCalGas, D.04-09-022 defined the supply standard for transportation contracts by "setting the minimum at the annual average daily (core demand) and the maximum at 120 percent of the annual average daily (core demand), for both the winter and non-winter months."[44] For PG&E, D.04-09-022 established a winter planning standard by setting the minimum at 116 percent of the annual average daily core demand and the maximum at 127 percent of annual average daily core demand. D.04-09-022 additionally established a summer planning

[43] D.04-09-022 at 28-29.

[44] D.04-09-022 at 31.

standard for PG&E by setting the minimum at 90 percent of the annual average daily core demand and the maximum at 127 percent of the annual average daily core demand.[45]

These standards were subsequently modified in D.06-10-029, D.07-12-019, D.08-12-020, D.15-10-050, D.19-09-025, and SoCalGas Advice Letter 3969. The table below shows the current core interstate pipeline supply standards.

Core Supply Standards: Firm Interstate Pipeline Capacity

% of Average Daily Demand	PG&E	SoCalGas
Winter[46]	100-162%	100-120%
March	80-162%	n/a
Summer	80-105%	90-120%

In the Workshop Report, Staff noted that the supply standards for core customers were not discussed at the workshops and recommended that parties to the proceeding consider whether the supply standards should be revisited.[47]

In response, PG&E, SoCalGas, UCAN, and SCGC indicated that core supply standards should not be considered in this proceeding. SoCalGas asserted that the adopted design standard will impact the level of flowing gas supply and that revisiting the supply standards before determining whether additional customers should be reclassified as core would be premature.[48] PG&E contended

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[45] Id. at 34.

[46] The gas winter is typically considered to be November through March. The summer is April through October.

[47] Workshop Report at 37.

[48] SoCalGas Comments of Southern California Gas Company (Assigned Administrative Law Judge's Ruling Issuing Workshop Report and Staff Recommendations, Seeking Comments, and Modifying Proceeding Schedule) at 29.

that its supply standards are working as intended and should not be revised at this time.[49] Similarly, UCAN stated that supply standards do not appear to be an issue. While we do not take a position on whether the core supply standards are adequate, we recognize that no party expressed a need to change them at this time. For this reason, we do not adopt any modifications to the core supply standards for SoCalGas and PG&E.

3.3. Should the Commission establish uniform reliability standards for PG&E and SoCalGas, rather than allow them to continue to use different standards?

In the Workshop Report, Staff recommended that the Commission eliminate all current infrastructure design standards and replace them with a 1-in-10-year peak day design standard for both PG&E and SoCalGas that can be met with a combination of pipeline and gas storage assets.[50] In making this recommendation, Staff acknowledged that various parties argued that the utilities have different systems and therefore should have different standards. However, Staff argued that the utilities are free to use their systems as they see fit to meet the proposed standard. Staff stated that the "goal in making this recommendation is to increase both simplicity and clarity without compromising reliability."[51]

Several parties expressed opposition to the recommendation to adopt uniform standards. PG&E explained that requiring a 1-in-10 peak day standard in lieu of its 1-in-90 and 1-in-2-year standards would jeopardize core customer

[49] PG&E Comments (Assigned Administrative Law Judge's Ruling Issuing Workshop Report and Staff Recommendations, Seeking Comments, and Modifying Procedural Schedule) at 2.

[50] Workshop Report at 37.

[51] Workshop Report at 36.

reliability and require significant investments on its local transmission and distribution system to support a more stringent standard for its noncore customers. PG&E faulted Staff's proposal for only including a temperature recurrence interval while excluding other factors that affect reliability, such as minimum design pressure, minimum pressure differential across regulation, and demand confidence level.[52] UCAN agreed with PG&E that further studies are needed to assess the potential need for capital investments on its system before adopting a 1-in-10 peak day design standard.[53] Alternatively, TURN suggested an approach that focuses on annual backbone capacity of the system rather than the proposed standard.

The Indicated Shippers, CEJA, Justice Parties, SBUA, and CEERT also opposed Staff's suggestion to apply uniform reliability standards for SoCalGas and PG&E. Parties, including SoCalGas and SDG&E filing jointly, PG&E, the Indicated Shippers, TURN, SCGC, and PCF, reiterated in opening and reply briefs that uniform standards for SoCalGas and PG&E are not necessary.

We recognize that the SoCalGas and PG&E gas systems are different. We also recognize that Staff's recommendation to apply uniform standards across both utilities did not consider additional factors that may impact the need for a certain design standard beyond a temperature recurrence interval. We therefore decline to adopt a uniform 1-in-10-year peak day design standard for SoCalGas and PG&E. As discussed above, this decision maintains all existing infrastructure design standards for both PG&E and SoCalGas.

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[52] PG&E Comments at 6.

[53] UCAN Reply Comments at 5.

We do, however, support Staff's goal of increasing clarity around the design standards. As discussed above, the California Gas Report does not currently include demand forecasts that exactly reflect the design standards. In order to provide a common reference for stakeholders, we require SoCalGas and PG&E to provide demand forecasts for the design standards adopted by D.06-09-039 in the 2024 California Gas Report and subsequent versions of the report. Specifically, we require that both PG&E and SoCalGas provide demand forecasts for the average day in a 1-in-10 cold and dry year standard. We require PG&E to provide demand forecasts of its 1-in-90 abnormal peak day and 1-in-2 cold day standards. We require SoCalGas to provide demand forecasts for its 1-in-35 extreme peak day and 1-in-10 cold day standards. We also require the utilities to include tables similar to the Core Supply Standards: Firm Interstate Pipeline Capacity table in Section 3.2 of this decision, showing their current supply standards for both interstate pipeline and storage contracts in the 2024 California Gas Report and subsequent versions of the report.

3.4. Will current reliability standards overstate the capacity that gas utilities must maintain?

The straightforward answer to this question is "No" because choosing an acceptable interval of curtailment, which is what the design standards do, does not create a problem of overstating demand. But how the standards are implemented depends on the assumptions that are used in the demand forecasts. The California Energy Commission (CEC) gave a presentation on temperature projections and demand trends at the July 7, 2020 workshop. The CEC presentation noted that average minimum temperatures are projected to increase through 2079, with the confidence intervals widening in later years, which means there is less certainty and more variability in the forecasts. The CEC also discussed how it uses climate change forecasts in its natural gas end-use forecasts. It has consumption models with weather parameters that tease out the effects of temperature. The results of the model—which forecast average annual impacts—show that climate change will drive a 1.6 to 1.8 percent reduction in overall gas use in 2030, which is largely a result of decline in residential demand.[54]

In the Workshop Report, Staff recommended requiring the gas utilities to use relevant climate data from California's Fourth Climate Change Assessment or the most recent California Climate Change Assessment available to adjust their cold day demand forecasts in the California Gas Report.[55] California's Climate Change Assessments use scientific research to characterize the impacts and risks of climate change to California and to identify potential climate adaptation and mitigation responses. California's Climate Change Assessments include peer-reviewed data and analyses portraying projected climate trends and their impact on California's energy sector. We found general support from parties for incorporating the latest California Climate Change Assessment into the gas utilities' cold day demand forecasts. Thus, we adopt Staff's recommendation to require SoCalGas and PG&E to review and use relevant climate data from California's Fourth Climate Change Assessment or the most recent version of California's Climate Change Assessment that is made available in the future in adjusting their cold day demand forecasts in the California Gas Reports. In using the latest Assessment, SoCalGas and PG&E should describe

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[54] Workshop Report at 6.

[55] *Id*. at 38.

what changes were made to the California Gas Report forecast based on the updated climate data.

The existing design standards are based on the number of curtailments that are acceptable within a given interval, e.g., there should be no curtailments on the coldest day in 10 years, but curtailments may be expected on the coldest day in 11 years. The utilities use probabilistic models that incorporate the historical record and some statistical measures to account for climate change to determine what temperatures should be used as benchmarks for the design standards. For example, in the 2020 California Gas Report, SoCalGas pegged its 1-in-35 standard to an average temperature in its service territory of 40.5°F.[56]

The question is whether the utilities are using reasonable temperature benchmarks given the warming climate. That question is hard to answer because the CEC's work to date has focused on projected *average* annual temperatures, while gas design standards are based on *extreme* cold weather events. Future editions of California's Climate Change Assessment may include more information on the probability of extreme winter cold events, which should be incorporated into the forecasts used by the utilities.

Track 2 of this Rulemaking focuses on planning needed to ensure a safe and reliable gas system as demand for fossil gas declines over time. The Amended Scoping Memo for Track 2 includes a track on data needs (Track 2c). Specifically, the data track seeks to answer questions about the types of data inputs and outputs that gas utilities should integrate into their gas demand forecasts, including for utility design standards.[57]

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[56] 2020 California Gas Report at 139.

[57] Assigned Commissioner's Amended Scoping Memo and Ruling: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M415/K275/415275138.PDF.

The record developed and the decisions made in the data track in Phase 2 of this proceeding will assist the utilities in modeling future temperatures to ensure that future gas demand is not overstated. In comments on the proposed decision, several parties recommended using the CEC's demand forecast rather than the California Gas Report once the CEC has developed such a forecast. When such a forecast is available from the CEC, we will consider whether to utilize that forecast at that time.

3.5. Should the Commission establish separate reliability standards for the summer months?

At the July 7, 2020 workshop, a coalition of electric generators—including SCGC, Vistra Energy, Middle River Power, and Calpine—indicated that since the California gas system is a winter peaking system, the ability to meet a winter standard will continue to be sufficient to also meet summer peak day demand. It stated that the 2018 California Gas Report peak day demand forecast for SoCalGas winter 2019-20 was 35 percent higher than summer 2020, and PG&E's winter 2019-20 demand was 56 percent higher than summer 2020.[58] Crossborder Energy[59] asserted that the current 1-in-10 cold and dry-hydroelectric year backbone standard already considers summer because hydroelectric conditions are a key driver of summer electric generation demand. These parties asserted that a summer reliability standard is not needed.[60]

The July 31, 2020 ALJ Ruling Seeking Comments, sought responses from parties regarding the need for a summer reliability standard. The July 31, 2020

[58] Workshop Report at 11.

[59] Crossborder Energy presented on behalf of a coalition of electric generators (Workshop Report at 12).

[60] Workshop Report at 12.

ALJ Ruling recognized that SCGC and Crossborder's assertion that a winter peaking system should be able to meet summer peak day demand does not consider differences in supply availability in the winter and summer. The July 31, 2020 ALJ Ruling used the SoCalGas system, which relies on storage to meet seasonal demand, as an example of how this issue could play out: "[A] very cold winter may result in depleted inventory levels prior to the summer season, which may present difficulties in meeting summer peak day demand."[61]

Most parties that responded to this question agreed that a summer reliability standard is not needed. TURN points out that since gas flows ratably through the pipelines, a gas utility may not be able to meet steep ramps in electric generation demand in the summer regardless of the standard employed. TURN states that to fix this problem for the SoCalGas system would require more flexible usage of Aliso Canyon in the near term and a concentrated effort to flatten electric generation demand in the long term.[62] Similarly, the Indicated Shippers contend that a winter reliability standard is sufficient to ensure that summer peak demand can be met because reasonable use of existing storage infrastructure should address concerns over potential difficulties in meeting summer peak demand.[63] Staff noted the consensus against establishing a summer reliability standard in the Workshop Report and recommended against adopting one.[64]

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[61] Assigned Administrative Law Judge's Ruling Seeking Comments, July 31, 2020, at 2.

[62] TURN Comments at 8.

[63] Indicated Shippers Comments (Response to July 31, 2020 Assigned Administrative Law Judge's Ruling Seeking Comments) at 15.

[64] Workshop Report at 38.

Parties largely agree that a gas system designed to meet winter reliability standards obviates the need for summer reliability standards. Therefore, we decline to adopt separate reliability standards for the summer months.

3.6. Should gas utilities maintain a specific amount of slack capacity or additional infrastructure above the amount of backbone transmission and storage capacity necessary to meet the existing 1-in-10 cold and dry year reliability standard? If so, how much and under what conditions?

At the July 7, 2020 Workshop, PG&E indicated that it still agrees with the slack capacity requirements established in D.06-09-039. It further noted that PG&E is looking for ways to retire infrastructure and lower its capacity because the utility has a large capacity surplus forecasted in the future.[65] SoCalGas stated that D.06-09-039 did not establish slack capacity percentages to maintain and that slack capacity does not include storage capacity.[66] SCGC and Indicated Shippers stated that slack capacity on the SoCalGas system has been reduced by maintenance activities and that improved access to storage withdrawals would compensate for that reduction.[67]

The July 31, 2020 ALJ Ruling Seeking Comments sought responses from parties on whether slack capacity should include storage (*i.e.*, whether slack capacity standards should be established for storage), since D.06-09-039 solely used intrastate pipeline capacity to measure a utility's slack capacity.[68] SoCalGas contends it would be more appropriate to include storage requirements as part of the reliability standards rather than slack capacity since the slack capacity

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[65] Workshop Report at 13.

[66] Workshop Report at 13.

[67] Workshop Report at 14.

[68] Assigned Administrative Law Judge's Ruling Seeking Comments, July 31, 2020, at 4.

calculation that was approved in D.06-09-039 is based on 1-in-10-year cold and dry conditions.[69] Similarly, PG&E asserts that incorporating storage into the slack capacity calculation would complicate gas design standards and be unmanageable for system operators. PG&E explains that a peak day standard is a better way to determine if there is adequate capacity to meet peak day needs.[70] Cal Advocates also expresses hesitation to include storage in the slack capacity requirements, explaining there could be cost implications for doing so.[71] Accordingly, Cal Advocates recommends that the best venue for deciding this issue would be the utilities' respective cost allocation proceedings.

Alternatively, Indicated Shippers recommends that slack capacity should include storage since California would be unable to consistently meet winter gas demand without it.[72] Middle River Power, SCGC, and SBUA also support including storage as part of slack capacity requirements.

In the Workshop Report, Staff explained that it did not have a specific slack capacity recommendation but that the PG&E and SoCalGas systems should be able to meet minimum design standards after an unexpected failure of a critical gas system component. Additionally, Staff addressed the existing reporting requirements for slack capacity. Currently, the gas utilities are required to file biennial advice letters on their slack capacity. Staff recommends that if an advice letter continues to be required, the gas utility should include a

[69] SoCalGas and SDG&E Joint Comments (July 31, 2020 Assigned Administrative Law Judge's Ruling Seeking Comments) at 29. (August 14, 2020)

[70] PG&E Response to Assigned Administrative Law Judge's Ruling Seeking Comments at 8.

[71] Cal Advocates Comments in Response to Assigned Administrative Law Judge's Ruling Seeking Comments at 13.

[72] Indicated Shippers Comments (July 31, 2020 Assigned Administrative Law Judge's Ruling Seeking Comments) at 24-25.

confidential section identifying the three most critical system components and the amount of capacity each supports.[73]

TURN and Calpine contend that the Commission should "exercise extreme caution" before adopting any additional slack capacity requirements that may result in excess gas infrastructure. PCF contends that the Commission should not increase slack capacity and instead utilize other programs to decrease demand on the system, such as demand response, energy efficiency and energy shifting from gas to the electric sector. Several parties support the continued requirement for gas utilities to file advice letters on slack capacity. Indicated Shippers, SCGC, and EDF indicate that the information in the advice letters regarding the top three critical components should not receive confidential treatment.

Parties largely agree that slack capacity requirements should not change, albeit for different reasons. We acknowledge TURN's comment that additional slack capacity requirements may potentially result in excess gas infrastructure. Although we decline to change existing slack capacity requirements, we agree that the utilities should continue to file advice letters on slack capacity requirements. For the reasons discussed above, Tier 2 advice letters on slack capacity shall be filed on a biannual basis (April 15 and October 15) rather than on a biennial basis and should be expanded to include the information on system capacity described in Section 3.1.3 above.

[73] Workshop Report at 38-39.

3.7. Does the construction of the Energía Costa Azul liquified natural gas (LNG) export terminal by SoCalGas affiliates Sempra LNG and Ienova and transportation of gas to that facility over the proposed North Baja Xpress Project create any reliability issue for the SoCalGas Southern System and, if so, what steps should be taken to address them?

SoCalGas responded to the above question at the July 7, 2020 workshop. The utility stated that the El Paso Natural Gas (EPNG) South Mainline is the source of supply for the North Baja Xpress project, and its delivery capacity to SoCalGas' Ehrenberg receipt point is 2.3 billion cubic feet per day (Bcfd). SoCalGas also indicated that its current takeaway at Ehrenberg is 1.2 Bcfd, and North Baja's is 0.51 Bcfd. The North Baja Xpress project would take an additional 0.48 Bcfd. Thus, the total takeaway with the North Baja Xpress project, 2.19 Bcfd, would still be within the available delivery capacity of 2.3 Bcfd.

SoCalGas additionally discussed the System Operator's obligation to preserve reliability on the Southern System pointing out that supplies to the Southern System had exceeded the minimum flow requirement every day for the preceding two storage cycles and noted that there is generally low demand on the Southern System.[74]

In the Workshop Report, Staff highlighted concerns about how SoCalGas derived the 2.3 Bcf delivery capacity figure but concluded that it likely has reasonable tools available at the moment to address Southern System reliability issues including: (a) spot market purchases at Southern Zone receipt points for subsequent sale at the Citygate; (b) memoranda in lieu of contract between its Gas Acquisition Department and System Operator for coverage of the Southern

[74] Workshop Report at 16.

System minimum requirements attributable to bundled core customers; (c) seasonal baseload transactions to secure preset daily delivery to Southern Zone receipt points; (d) discounted backbone transportation service (BTS) contracts applicable to Southern Zone receipt points; and (e) ability to issue a Request for Proposals (RFP) seeking additional tools.

There was limited comment on this issue from the parties. TURN and SCGC maintained that the five tools available to the System Operator are adequate to maintain Southern System reliability for now. None of the parties expressed concerns about the adequacy of these tools to maintain Southern System reliability.

Events since the July 7, 2020 workshop have sharpened concerns about the availability of gas to SoCalGas' Southern System. An indefinite outage on one of the mainline pipelines on the EPNG South Mainline, after an explosion in Coolidge, Arizona in August 2021, has reduced the total amount of gas that can reach the SoCalGas Southern System.

At this time, we do not determine whether the five tools discussed above will be adequate to address potential Southern System Reliability issues raised by the construction of Energía Costa Azul liquified natural gas export project by SoCalGas affiliates Sempra LNG and IEnova and transportation of gas to that facility over the proposed North Baja Xpress Project. On April 21, 2022, FERC approved an Order Issuing Certificate for the North Baja Xpress Project in FERC Docket CP20-27.[75] Staff may revisit the adequacy of these measures as the project proceeds and more information regarding the logistics of transportation

[75] *North Baja Pipeline LLC, Order Issuing Certificate*, 179 FERC ¶ 61,039 (2022).

arrangements over the North Baja Pipeline and its impact on Southern System reliability becomes available.

Because this decision does not update existing reliability standards, cost recovery and allocation analyses are not needed at this time.[76]

4. Track 1B: Market Structure and Regulations

4.1. What measures, if any, can be taken to ensure interstate pipeline transportation capacity reliability?

At the July 21, 2020 workshop, Southwest Gas noted that if California's noncore customers and regulated utilities are unwilling to enter into long-term interstate contracts, there could be interstate service volatility. In response to Scoping Memo Issue 1a, Southwest Gas offered three potential solutions to this problem, including:

1. Requiring Commission-regulated utilities to secure long-term, firm interstate capacity contracts;[77]
2. Requiring long-term California border and Citygate contracts; and
3. Holding Commission-led workshops with interstate pipeline operators to address potential service reliability issues.

At the July 21, 2020 workshop, Calpine challenged the notion that electric generators should hold firm interstate long-term contracts, indicating that such an arrangement only makes sense if the generator has a high load factor and can recover the fixed costs associated with long-term firm contracts. Moreover, Calpine implied that it would be difficult for a generator with a fixed capacity

[76] Scoping Memo question 5.

[77] Workshop Report at 19.

contract to operate in the electric market because it is difficult to operate flexibly without accruing steep costs.[78]

Independent Energy Producers reiterated that there is no need for gas generators to buy long-term firm contracts. CEERT—in its response to the July 31, 2020 ALJ Ruling—indicated that requiring electric generators to hold additional firm interstate capacity contracts would not improve gas system reliability.[79] Calpine, in response to the same ruling, argued that forcing electric generators to pay higher gas rates could make them less competitive in the CAISO electric market.[80] EDF also expressed concerns about requiring electric generators to hold firm pipeline capacity, stating that such a proposal could drive up contract costs and send a false signal that more gas infrastructure should be built.[81] SBUA also noted that there is sufficient interstate pipeline capacity, and the focus should instead be on intrastate capacity. No party, other than Southwest Gas, expressed support for requiring California customers to hold additional interstate capacity contracts.

We recognize Southwest Gas' concerns that if competing customers purchase more firm contracts on interstate pipelines, California's noncore customers and regulated utilities, including electric generation customers, who typically do not hold firm contracts, could potentially be squeezed out. Southwest Gas further argues that reliability problems stemming from a lack of firm interstate contracts could potentially be exacerbated by uncommitted

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[78] *Id.* at 20.

[79] Opening Comments of The Center for Energy Efficiency and Renewable Technologies on the Assigned Administrative Law Judge's Ruling Seeking Comments, August 14, 2020, at 8.

[80] Calpine Comments (August 14, 2020) at 5.

[81] EDF Opening Comments (Workshop Report, November 2, 2020) at 14.

capacity being sold to markets upstream of California such as increasing gas exports to Mexico. The Commission recognizes reliability problems can also come about by other Western states upstream of California building new gas-fired electric generation plants, an increase in gas exports to Mexico and/or the expansion of liquified natural gas facilities.

Given that there is no support by any other party for Southwest Gas' position, we are not persuaded that that Commission-regulated electric generators should be required to secure long-term, firm interstate gas contracts at this time. We may, however, revisit this question in the future.

4.2. Electric Generators

This section includes discussion questions 1b and 1c. First, what measures if any can be taken to ensure that gas needs of electric generators are met during hourly and intraday fluctuations? Second, what measures if any can be taken to ensure that gas needs of electric generators are met during multiple days of low renewable generation?

At the July 20, 2020 workshop, the California Council on Science and Technology highlighted the need for gas storage to help meet electric generation demand during periods of low renewable generation. Wood Mackenzie's presentation included a discussion of its "Western Interconnection Gas-Electric Interface Study." One of its recommendations is to reclassify some electric generators as core customers, which would ensure that critical power plants are not the first to be curtailed.

The July 31, 2020 ALJ Ruling Seeking Comments sought responses from parties regarding the idea of reclassifying some electric generators as core customers, which would ensure that critical power plants are not the first to be curtailed and whether such reclassified customers should have access to firm storage rights. SoCalGas contended that the results of the Aliso Canyon Investigation (I.17-02-002) may change its available storage capacity.[82] Similarly, TURN indicated that the only way to ensure enough storage capacity for peak electric generation demand in the summer and peak core demand in the winter would be to remove the current restrictions on Aliso Canyon. TURN also suggested that if some electric generators are reclassified as core customers, the Commission should work with CAISO to determine the quantity of electric generation gas supply that should be reclassified as core and allow CAISO to determine which power plants are dispatched and when.[83] CAISO stated that it is more important to designate a minimum volumetric flow of gas that is needed to support electric reliability than to identify specific core generators. It stated that this approach would better align electric needs with gas planning.[84]

Several parties opposed the idea of reclassifying electric generators as core customers, including Indicated Shippers, Calpine, SCE, and PCF. Some parties argued that electric generators should have more access to storage without reclassification. Unlike SoCalGas, PG&E assumed that it has enough storage to meet the needs of an expanded core class. PG&E, however, contended that the utilities should be required to do a detailed study to ensure sufficient capacity of all available assets.[85]

In response to these comments, Staff recommended that CAISO submit a proposal outlining a mechanism for determining the minimum amount of gas

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[82] SoCalGas and SDG&E Joint Comments (July 31, 2020 Ruling) at 25. (August 14, 2020)

[83] TURN Comments (July 31, 2020 Ruling) at 10 to 11.

[84] Responses of The California Independent System Operator Corporation to Questions Set Forth in The Administrative Law Judge's Ruling Seeking Comments, August 14, 2020, at 3.

[85] PG&E Response (August 14, 2020) at 7-8.

supply needed for electric reliability in California and how the CAISO would allocate that gas to generators bidding into the market.[86] CAISO, however, contended that it cannot provide a planning level mechanism for determining the minimum gas supply requirements, in light of unanswered questions regarding long-term gas needs for electric generation. Additionally, CAISO asserted that it does not have authority to allocate gas to specific generators under its tariff. In addition, some parties expressed concerns about how the designated gas supply would be allocated and what impact it would have on the CAISO market.[87]

Considering the concerns shared by parties, we decline to adopt the recommendation that CAISO submit a planning proposal. While parties recognize that gas continues to play a critical role in fulfilling electric reliability needs, there were no viable mechanisms proposed that would ensure gas supply security for the electric system. Accordingly, we decline to adopt any specific measures at this time.

4.3. Should the Commission establish contract or tariff terms and conditions or new rules to attempt to decrease the risk of electricity price volatility caused by potential gas supply issues?

At the July 24, 2020 workshop SoCalGas asserted that its Rule No. 30 tariff requires gas deliveries to flow ratably within a gas day but that intraday variability of gas-fired electric generation is increasing with the use of renewables, which causes more ramping issues on the gas system. SoCalGas recommended a new tariff structure to accommodate and better capture the non-ratable gas supply needs of electric generators, a proposed "Renewable

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[86] Workshop Report, at 1.

[87] CAISO Comments (November 2, 2020) at 2.

Balancing Service," which would raise cost allocation considerations. SCE advocated for a cost-based voluntary tariff for CAISO-connected electric generators. Under SCE's proposed mechanism, the gas utility would be responsible for managing risk.[88]

In the Workshop Report, Staff acknowledged that parties had lingering questions about how SoCalGas's proposed tariff would work and recommended that both SoCalGas and PG&E submit formal analyses outlining a proposal for a "Renewable Balancing Tariff."[89] The October 2, 2020 ALJ Ruling directed SoCalGas and PG&E to hold workshops and engage with parties on what their "Renewable Balancing Tariff" proposals might entail. As part of its proposal, PG&E suggested continuing use of its Inventory Management Service, which was approved as part of its 2019 Gas Transmission and Storage (GT&S) rate case.[90] PG&E explained that intraday demand variations are not limited to gas-fired electric generators and can occur as a result of core and noncore industrial customer behavior.[91] The utility stated that its Inventory Management service is designed to compensate for intraday fluctuations in pipeline inventory to keep operating pressures within safe parameters. The program supports system balancing by allowing enough storage capacity to be set aside to resolve intraday fluctuations.[92] PG&E indicated that costs to support the program are allocated fairly to all customers. It further asserted that the program contributed

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[88] Workshop Report at 29.

[89] Workshop Report at 42.

[90] D.19-09-025.

[91] PG&E's Renewable Balancing Tariff Proposal In Response to Assigned Administrative Law Judge's Ruling Issuing Workshop Report and Staff Recommendations, Seeking Comments, and Modifying Proceeding Schedule, January 8, 2021, at 4.

[92] *Id*. at 6.

to a 56 percent decrease in Operational Flow Orders for the period April 1 to October 31, 2020 compared to the same time period in 2019.[93] Lastly, PG&E explained that any revisions or potential improvements to the program can be made in future GRCs.[94]

SoCalGas' proposal for a "Renewable Balancing Service" tariff includes two key elements: "1) more granular shaped flow scheduling for [electric generators]; and 2) updated granular rate structures for [electric generators]."[95] With regard to the first component, SoCalGas proposed that electric generation customers be required to provide projected hourly usage information to the gas company based on accepted electric Day-Ahead Market clearing bids or dispatch orders by the Cycle 2 nomination deadline[96] and to revise those projections as necessary within the Gas Day. With regard to the second component, SoCalGas proposed a three-tier rate structure for electric generation customers based on customer load factor. This proposal is different from the current rate design structure, which has one general rate for electric generation customers.[97]

There was consensus among the parties that SoCalGas's proposal for a "Renewable Balancing Tariff" is insufficiently developed in its current form. In addition, several parties agreed with PG&E that its Inventory Management Service is working as intended and provides balancing services for intraday demand changes. In its comments on the "Renewable Balancing Tariff"

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[93] *Id*. at 7.

[94] *Id*. at 8.

[95] SoCalGas' Proposal For A Conceptual Renewable Balancing Services Tariff, January 8, 2021, at 13.

[96] Cycle 2 (also known as Evening Cycle) nominations must be made before 4:00 p.m. on the day before the gas is delivered.

[97] *Id*. at 13-14.

proposals submitted by the utilities, Indicated Shippers argued that balancing mechanisms should be considered in utility-specific rate cases as those venues best address operational impacts and associated costs.[98]

We recognize that PG&E's Inventory Management Service was created to provide balancing services for all customers using PG&E's storage assets. PG&E indicates that electric generation customers are not solely responsible for intraday imbalances on its system while SoCalGas contends that gas usage activity of its electric generation customers is volatile and differs from the usage of other customer types. We also agree with parties that SoCalGas did not provide enough information on how to implement its conceptual "Renewable Balancing Tariff." Therefore, we decline to adopt the proposed Renewable Balancing Tariff concept here. SoCalGas may propose this concept, with sufficient implementation details, in a future ratemaking or cost allocation proceeding.

5. Comments on Proposed Decision

The proposed decision of ALJs Bemesderfer and Goldberg in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on June 9, 2022 by TURN, EDF, SCGC, UCAN, Indicated Shippers, PG&E, Southwest Gas, CALISO, California Environmental Justice Alliance, and SoCalGas, and reply comments were filed on June 14, 2022 by Middle River Power LLC, Calpine, PG&E, TURN, UCAN, Indicated Shippers, SoCalGas and SDG&E filing jointly, and SCGC.

[98] Indicated Shippers Comments at 3.

In response to comments, the proposed Citation Program and the Force Majeure Clause were modified as indicated in the text of this decision, including Appendix A hereof. Minor modifications and clarifications were made to the text of the decision and to the Findings of Fact, Conclusions of Law and Ordering Paragraphs to improve clarity and consistent with suggestions from various parties.

6. Assignment of Proceeding

Clifford Rechtschaffen is the assigned Commissioner and Karl Bemesderfer is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. System capacity at any point in time is the sum of a gas utility's current transmission and storage capacity.

2. Slack capacity at any point in time is current backbone transportation system capacity in excess of forecasted customer demand for an average day in a 1-in-10 cold and dry year.

3. The backbone capacity of a gas utility's system varies due to planned and unplanned maintenance as well as changes in supply.

4. The Commission established backbone and local transmission and peak day standards for PG&E and SoCalGas in D.06-09-039.

5. D.06-09-039 requires that both PG&E and SoCalGas maintain adequate backbone capacity to meet all system demand on an average day in a 1-in-10 cold and dry-hydroelectric year.

6. Sustained failure of PG&E or SoCalGas to meet the backbone capacity requirements imposed by D.06-09-039 would have serious negative health, safety and economic effects.

7. D.19-09-025 established a 1-in-10-year peak day backbone planning standard for PG&E.

8. For PG&E, the local transmission peak day design standard requires that it serve all customers on a 1-in-2 winter cold day and core customers only on an abnormal 1-in-90 winter peak day.

9. PG&E has the requisite gas backbone pipeline and storage capacity to meet average day demand in a 1-in-10 cold and dry-hydroelectric year and its abnormal peak day demand as forecasted in the 2020 California Gas Report.

10. For SoCalGas, the peak day design standard requires that it serve all customers on a 1-in-10 peak day and core customers only on a 1-in-35 extreme peak day.

11. SoCalGas has the requisite gas transmission pipeline and storage capacity to meet demand for an average day in a 1-in-10 cold and dry-hydroelectric year and the 1-in-35 extreme peak day demand but not the 1-in-10 cold day demand as forecasted in the 2020 California Gas Report.

12. The CEC has noted that average minimum temperatures are projected to increase through 2079, with the confidence intervals widening in later years leading to less certainty and more variability in the forecasts.

13. The CEC's work to date has focused on projected *average* annual temperatures, while gas design standards are based on *extreme* cold weather events.

14. California's Climate Change Assessments use scientific research to characterize the impacts and risks of climate change to California and to identify potential climate adaptation and mitigation responses.

15. California's Climate Change Assessments include peer-reviewed data and analyses portraying projected climate trends and their impact on California's energy sector.

16. The California Gas Report does not currently include demand forecasts that exactly reflect the design standards

17. The California Gas Report does not currently contain sufficient details to effectively evaluate the ability of utilities to meet their average day in a 1-in-10 cold and dry year standards and their peak day standards.

18. PG&E and SoCalGas are required to file advice letters on slack capacity biennially per D.06-09-039.

19. PG&E and SoCalGas are not currently required to state the operating capacities of the utilities' backbone transmission lines/zonal areas or paths in their biennial advice letters filed in compliance with D.06-09-039.

20. SoCalGas currently has reasonable tools available to address Southern System reliability issues including: (a) spot market purchases at Southern Zone receipt points for subsequent sale at the Citygate; (b) memoranda in lieu of contract between its Gas Acquisition Department and System Operator for coverage of the Southern System minimum requirements attributable to bundled core customers; (c) seasonal baseload transactions to secure preset daily delivery to Southern Zone receipt points; (d) discounted backbone transportation service (BTS) contracts applicable to Southern Zone receipt points; and (e) ability to issue a Request for Proposals (RFP) seeking additional tools.

Conclusions of Law

1. PG&E and SoCalGas should be required to maintain adequate backbone capacity to meet the average day in a 1-in-10 cold and dry year standard established by D.06-09-039.

2. SoCalGas and PG&E should use relevant data from the most recent California Climate Change Assessment as an input in their cold day demand forecasts in the California Gas Reports and describe what changes were made to the California Gas Report forecast based on the updated climate data.

3. Transparency is improved if information on utilities' most current supply standards for interstate pipeline and storage contracts is centralized in the California Gas Report.

4. SoCalGas and PG&E should include tables similar to the "Core Supply Standards: Firm Interstate Pipeline Capacity" table in Section 3.2 of this decision, describing the current supply standards for both interstate pipeline and storage contracts in the 2024 and subsequent versions of the California Gas Report.

5. It is critical to have accurate demand forecasts for an average day in a 1-in-10 cold and dry hydroelectric year to determine whether a utility is meeting its backbone capacity standard.

6. SoCalGas and PG&E should provide demand forecasts for the average day in a 1-in-10 cold and dry hydroelectric year design standard adopted by D.06-09-039 in the 2024 California Gas Report and subsequent versions of the report.

7. In order for the Commission to ascertain whether a utility is meeting its peak day standards, it must have accurate peak day demand forecasts.

8. Pacific Gas and Electric Company should provide demand forecasts of its 1-in-90 abnormal peak day and 1-in-2 cold day local transmission standards and 1-in-10-year peak day standard for backbone and storage capacity in the 2024 California Gas Report and subsequent versions of the report.

9. Southern California Gas Company should provide demand forecasts for its 1-in-35 extreme peak day and 1-in-10 cold day standards in the 2024 California Gas Report and subsequent versions of the report.

10. SoCalGas and PG&E should file their advice letters on slack capacity biannually rather than biennially and include detailed information about their actual, rather than their nominal backbone transmission capacity, and whether that capacity is sufficient to meet the average day in a 1-in-10 cold-and-dry hydroelectric year backbone capacity standard.

11. Financially penalizing a gas utility for sustained failure to maintain minimum design standards is a reasonable means of ensuring compliance with such standards. A citation program is a reasonable means of imposing such financial penalty.

12. Nine months is a reasonable amount of time for a gas utility to address maintenance outages that hinder its ability to meet minimum design standards.

13. The Commission's Utility Enforcement Branch should be directed to issue citations and levy fines for sustained failure to meet minimum design standards.

14. The Commission should direct the Utility Enforcement Branch to propose a Citation Program for the Commission's consideration consistent with Resolution ALJ-377 and the "Citation Framework for Failure to Meet Minimum Design Standards Established by D.06-09-039" attached as Appendix A to this decision.

15. Penalties paid by shareholders for a gas utility's failure to meet minimum design standards are not recoverable expenses in current or future Commission proceedings or advice letters.

16. The Commission should adopt the following definition of gas reliability: *Gas reliability is a measure of the gas system's capacity and ability to deliver* *uninterrupted service. It consists of adequate physical and operational capacity to transport gas in amounts sufficient to meet customer demand.*

O R D E R

IT IS ORDERED that:

1. The Commission's Utility Enforcement Branch is directed to propose a Citation Program consistent with the "Citation Framework for Failure to Meet Minimum Design Standards Established by D.06-09-039" attached as Appendix A by issuing a draft Resolution for the Commission's consideration with service of the draft Resolution on the R.20-01-007 service list.

2. Upon adoption of a Resolution establishing a Citation Program for Failure to Meet Minimum Design Standards Established by Decision 06-09-039, the Commission's Utility Enforcement Branch is directed to issue citations and levy fines upon Pacific Gas and Electric Company and Southern California Gas Company for their sustained failure to meet the minimum design standards consistent with that Resolution.

3. Unless its failure is excused by a force majeure event, a gas utility whose daily available backbone capacity fails to meet the minimum design standard set out in Ordering Paragraph 4 below will be subject to a penalty of $50,000 per day for each day beyond nine months that it remains out of compliance. If the utility remains out of compliance for twelve months or more, the daily penalty will increase to $75,000 for each day beyond twelve months that it remains out of compliance.

4. Maintaining adequate backbone capacity to meet the average day in a 1-in-10 cold and dry year standard established by Decision 06-09-039 is adopted as the minimum design standard for Pacific Gas and Electric Company and Southern California Gas Company.

5. Pacific Gas and Electric Company and Southern California Gas Company shall report biannually (on April 15 and October 15) on any changes impacting their ability to meet the minimum design standard, specifying the actual operating capacities of the utilities' backbone transmission lines/zonal areas or paths not the nominal capacities as described in Appendix A, Attachment 1.

6. Southern California Gas Company and Pacific Gas and Electric Company shall provide demand forecasts for their average day in a 1-in-10 cold and dry year backbone capacity standards in the 2024 California Gas Report and subsequent versions of the report.

7. Pacific Gas and Electric Company shall provide demand forecasts of its 1-in-90 abnormal peak day and 1-in-2 cold day local transmission standards and 1-in-10-year peak day backbone standard in the California Gas Report in the 2024 California Gas Report and subsequent versions of the report.

8. Southern California Gas Company shall provide demand forecasts for its 1-in-35 extreme peak day and 1-in-10 cold day standards in the 2024 California Gas Report and subsequent versions of the report.

9. Southern California Gas Company and Pacific Gas and Electric Company shall provide tables similar to the Core Supply Standards: Firm Interstate Pipeline Capacity table in Section 3.2 of this decision, describing the current supply standards for both interstate pipeline and storage contracts in the 2024 California Gas Report and subsequent versions of the report.

10. The following definition of reliability is adopted: *Gas reliability is a measure of the gas system's capacity and ability to deliver uninterrupted service. It consists of adequate physical and operational capacity to transport gas in amounts sufficient to meet customer demand.*

11. Rulemaking 20-01-007 remains open.

This order is effective today.

Dated July 14, 2022, at Diamond Bar, California.

ALICE REYNOLDS
President
CLIFFORD RECHTSCHAFFEN
GENEVIEVE SHIROMA
DARCIE L. HOUCK
Commissioners

Commissioner John Reynolds, being necessarily absent, did not participate.

APPENDIX A

APPENDIX A

Citation Framework for Failure to Meet Minimum Design Standards Established by D.06-09-039

1. Minimum Design Standard: Pacific Gas and Electric Company (PG&E) and Southern California Gas Company (SoCalGas) are required to maintain adequate backbone capacity to meet the average day in a 1-in-10 cold and dry year standard established by D.06-09-039. This standard serves as a floor below which the daily available backbone capacity may not fall.
2. Penalty Structure: If a utility's daily available backbone capacity remains below the average day in a 1-in-10 cold and dry year standard established by D.06-09-039, the utility will be subject to a penalty of $50,000 per day for each day beyond nine months that it remains out of compliance. If the utility remains out of compliance for twelve months or more, the daily penalty will increase to $75,000 for each day beyond twelve months that it remains out of compliance.
3. Reporting Requirement: The utilities must report biannually (on April 15 and October 15) on any changes impacting their ability to meet the minimum design standard in the Tier 2 advice letters on slack capacity that they are required to file by D.06-09-039. These Tier 2 advice letters should be served on the R.20-01-007 service list and must specify the actual—not the nominal—average Cycle 1 operating capacities of the utilities' backbone transmission pipelines by zonal area or path over the previous nine-month period in both million cubic feet per day (MMcfd) and dekatherms (Dth) according to the formulas described in Appendix A, Attachment 1.

   The utilities must separately notify Energy Division and the R.20-01-007 service list via a Tier 1 Advice Letter on the first day the backbone transmission capacity fails to meet the minimum design standard as described in Appendix A, Attachment 1. Utilities must report their available backbone capacity in both million cubic feet per day (MMcfd) and dekatherms (Dth) in this Tier 1 advice letter. Staff will verify whether the actual operating capacities reported by the utilities in the biannual advice letters are accurate by comparing the reported figures with available capacities shown on SoCalGas' Envoy and PG&E's Pipe Ranger websites.

If staff is unable to verify the information contained in an advice letter and staff's calculations indicate that the utility is not meeting the minimum design standard, staff will draft a resolution proposing a revised capacity level reflecting figures derived from SoCalGas' Envoy or PG&E's Pipe Ranger websites as described in Appendix A, Attachment 1.

4. <u>Referrals to Utility Enforcement Branch Under Citation Program</u>: If Energy Division determines that a utility is out of compliance with the minimum design standard for over nine months after it first was out of compliance, it will refer the matter for investigation to the Commission's Utility Enforcement Branch to determine appropriate action, with service of the referral on the R.20-01-007 service list. The Utility Enforcement Branch is directed to issue citations and levy fines in accordance with Resolution ALJ-377 and the penalty structure described in this decision. Penalties are borne by shareholders and are not a recoverable expense in future rate case or advice letter filings.

5. <u>Force Majeure Clause</u>: A utility is not considered out of compliance if a force majeure event prevents it from meeting the minimum design standard. The utility shall use all reasonable efforts to mitigate the consequences of force majeure events with reasonable dispatch. The following definition of a force majeure event shall apply:

Force Majeure Event:

An event beyond the reasonable control of the Utility including, without limitation, an act of a governmental authority in the exercise of its jurisdiction*;* a state of emergency declared by federal or state authorities*; natural disasters such as fires, floods and earthquakes; strikes; and civil disorders.* The occurrence of high demand for gas service due to weather conditions shall not constitute a force majeure event.

APPENDIX A, ATTACHMENT 1
SAMPLE CALCULATIONS OF TOTAL AVAILABLE CAPACITY

For PG&E, the total available capacity for any given day consists of the capacity made available on Pipe Ranger in Cycle 1 for scheduling on the Redwood and Baja-Topock paths, plus the amount of California Production gas actually scheduled in Cycle 1.

PG&E's total available capacity will be verified by accessing the Pipe Ranger home page and downloading the relevant gas day information in the Interactive Pipeline Map section of the page as seen in the example below.

Category	Gas Day	Physical Pipeline Capacity (Dth)	Scheduled Volumes (Dth)	Available Operating Capacity (Dth)
Malin	06/30/2022	2,177,780	1,495,562	682,218
Onyx Hill	06/30/2022	1,558,500	211,616	1,346,884
Redwood Path	06/30/2022	1,848,886	1,707,178	141,708
CA Production	06/30/2022	Not Applicable	24,481	Not Applicable
Kettleman	06/30/2022	409,605	302,895	106,710
Kern River Station	06/30/2022	659,293	260,782	398,511
Freemont Peak Delivery	06/30/2022	290,742	0	290,742
Freemont Peak Receipts	06/30/2022	290,742	0	290,742
Hinkley	06/30/2022	732,169	563,677	168,492
Daggett	06/30/2022	386,625	32,061	354,564
Topock	06/30/2022	967,691	531,616	436,075
Topock North	06/30/2022	396,550	228,047	168,503
Topock South	06/30/2022	1,160,641	303,569	857,072

The calculation for the June 30, 2022, PG&E example above is as follows:

Receipt Point	Category	Quantity (Dth)
Redwood Path	Available Capacity	1,848,886
Baja–Topock	Available Capacity	967,691
California Production	Scheduled Volume	24,481
Total Available Capacity		2,841,058

For SoCalGas, total available capacity is equal to the sum of the following: 1) the capacity available for Total North Desert and Total Wheeler Ridge; 2) the capacity available for the Blythe Sub-Zone plus the scheduled volume at Otay Mesa, the sum of these not to exceed 1,210 MMcfd; and 3) scheduled volumes for Total California Production.

The total available capacity will be verified by accessing Envoy/Informational Postings/Operations/Capacity Utilization/Cycle 1 Timely.[99] The "available capacity" at each receipt point corresponds to the Latest On-System Gross Operating Capacity (Dth) column, and the "scheduled volume" corresponds to the Scheduled (Dth)/On System column, as seen in the exemplary screenshot below.

[99] For example, the page for June 30, 2022, can be found here: https://www.socalgasenvoy.com/#nav=/Public/ViewExternalCapacity.getCapacity%3FFileName%3D%26Class%3D%26gasFlowDate%3D06%252F30%252F2022%26HiddenGasFlowDateField%3D07%252F01%252F2022%26HiddenCycleField%3D2%26EXTERNAL_VIEW_INDICATOR%3Dfalse%26cycle%3D1%26rand%3D11.

Date : 06/30/2022 Cycle : 1 Timely

Capacity Utilization - 06/30/2022 - Timely

Archive | Description of Operating Capacity

Cycle Status: Approved

Balancing Status: Monthly

Receipt Point	Latest On-System Gross Operating Capacity (Dth)	Latest Scheduled (Dth)		On-System (Dth)			Off-System (Dth)	Confirmed (Dth)		Scheduled (Dth)	
		On-System	Off-System	Minimum Flow Requirement	Operating Capacity	Gross Operating Capacity	Operating Capacity	On-System	Off-System	On-System	Off-System
Total California Production	343,929	88,964		0	343,000	343,929		89,536		89,536	
Line 85	66,179	55,000		0	66,000	66,179		55,000		55,000	
North Coastal	165,447	14,096		0	165,000	165,447		14,554		14,554	
Other	112,303	19,868		0	112,000	112,303		19,982		19,982	
Total South Desert	781,109	609,716	0	421,137	778,000	780,106	0	707,135	0	490,980	0
Blythe	1,005,715	609,716	0	1	1,003,000	1,005,715	0	707,135	0	490,980	0
El Paso - Ehrenberg	1,252,381	609,716	0	0	1,249,000	1,252,381	0	707,135	0	490,980	0
NBP - Blythe	618,670	0	0	0	617,000	618,670	0	0	0	0	0
TGN - Otay Mesa	413,115	0	0	0	412,000	413,115	0	0	0	0	0
Total North Desert	1,290,484	956,180	0	0	1,281,000	1,284,468	0	956,251	0	931,936	0
Needles/Topock Area	856,312	516,693	0	0	850,000	852,301	0	527,341	0	508,545	0
Topock	356,964	256,251	0	0	355,000	355,961	0	282,755	0	264,241	0
El Paso - Topock	553,494	195,239	0	0	552,000	553,494	0	212,397	0	193,883	0
Transwestern - Topock	308,834	61,012	0	0	307,000	307,831	0	70,358	0	70,358	0
North Needles	825,228	260,442	0	0	820,000	822,220	0	244,586	0	244,304	0
Transwestern - Needles	825,228	260,442	0	0	820,000	822,220	0	244,586	0	244,304	0
Southern Trails- Needles	0	0	0	0	0	0	0	0	0	0	0
Kern River/Mojave - Kramer Junction	574,551	439,487	0	0	573,000	574,551	0	428,910	0	423,391	0
Kern River - Kramer Junction	574,551	439,436	0	0	573,000	574,551	0	428,778	0	423,262	0
Mojave - Kramer Junction	574,551	51	0	0	573,000	574,551	0	132	0	129	0
Total Wheeler Ridge	827,234	662,547	0	0	823,000	825,228	0	710,713	0	679,000	0
Kern River/Mojave	827,234	340,539	0	0	823,000	825,228	0	416,020	0	403,876	0
Kern River - Wheeler Ridge	827,234	335,539	0	0	823,000	825,228	0	411,020	0	398,876	0
Mojave - Wheeler Ridge	827,234	5,000	0	0	823,000	825,228	0	5,000	0	5,000	0
North - Wheeler Ridge	564,524	322,008	0	0	563,000	564,524	0	294,693	0	275,124	0
Pacific Gas & Electric	562,519	307,008	0	0	562,000	563,522	0	279,693	0	260,124	0
Elk Hills	155,420	15,000		0	155,000	155,420		15,000		15,000	
Total:		2,317,407	0					2,463,635	0	2,191,452	0

The calculation for the June 30, 2022, SoCalGas example above is as follows:

Receipt Point	Category	Quantity (Dth)
Total North Desert	Available Capacity	1,290,484
Total Wheeler Ridge	Available Capacity	827,234
Blythe Sub-Zone	Available Capacity	1,005,715
Otay Mesa	Scheduled Volume	0
Total California Production	Scheduled Volume	89,536
Total Available Capacity		3,212,969

(END OF APPENDIX A)