STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

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September 27, 2023

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Ratesetting

TO PARTIES OF RECORD IN RULEMAKING 20-01-007:

This is the proposed decision of Administrative Law Judge Cathleen A. Fogel. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's November 30, 2023 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties to the proceeding may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure (Rules).

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, *ex parte* communications are prohibited pursuant to Rule 8.2(c)(4).

/s/ MICHELLE COOKE
Michelle Cooke
Acting Chief Administrative Law Judge

MLC:nd3
Attachment

<u>PROPOSED DECISION OF ALJ FOGEL</u> (Mailed 9/27/2023)

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 PHASE 2 ISSUES REGARDING TRANSMISSION PIPELINES AND STORAGE

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DECISION ON PHASE 2 ISSUES REGARDING TRANSMISSION PIPELINES AND STORAGE

Summary

This decision resolves issues regarding transmission pipelines and natural gas storage facilities included in the *Assigned Commissioner's Phase 2 Scoping Memo and Ruling* issued on August 1, 2023. This decision adopts review criteria and information requirements for gas utility applications proposing to repair or replace transmission pipeline infrastructure. It adopts criteria to determine when declining demand can enable transmission pipelines to be derated or decommissioned without adversely impacting reliability. It requires gas utilities to provide an information-only submittal describing planned transmission pipeline derations.

This decision does not adopt new definitions of "transmission pipeline" or "distribution pipeline." Instead, it reinforces that gas utilities must continue to comply with California Public Utilities Commission General Order 112-F requirements to align with Pipeline and Hazardous Materials Safety Administration definitions of these terms as most recently set forth in Code of Federal Regulations (CFR) Title 49 Part 192.3 or as amended, if relevant, in the future. This decision adopts a proposal by Pacific Gas and Electric Company (PG&E) to update its definition of the term "transmission [pipe]line" and related terms in alignment with 49 CFR Part 192.3.[1] This results in the reclassification of some 600 miles of PG&E transmission pipeline as distribution pipeline.

This decision finds that natural gas storage facilities are necessary for reliability and cost management.

[1] For consistency, references to "transmission line" have been changed to "transmission pipeline" throughout this decision.

1. Background

The California Public Utilities Commission (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[2] and reply comments from fourteen parties,[3] the assigned Commissioner issued a Scoping Memo and Ruling (Scoping Memo) on April 23, 2020.

The Scoping Memo divided the proceeding into two separate tracks, with a Commission decision to follow each track. Track 1 included two sub-tracks, Track 1A and Track 1B. Track 1A addressed gas system reliability standards; Track 1B addressed regulatory changes needed to improve coordination between gas utilities and gas-fired electric generators. Track 1A and Track 1B issues were resolved in Decision (D.) 22-04-042 and D.22-07-012. Track 2A(a) issues were

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[2] Opening comments were received from The Utility Reform Network (TURN); Southern California Generation Coalition (SCGC); Middle River Power, LLC (MRP); Sacramento Municipal Utility District; 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; Calpine Corporation; California Hydrogen Business Council (CHBC); and Wild Tree Foundation.

[3] 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; SDG&E/SoCalGas; TURN; SCGC; and the Public Advocates Office of the California Public Utilities Commission (Cal Advocates).

resolved in D.22-12-027, which adopted General Order (GO) 177 regarding gas infrastructure projects that meet certain criteria.

Track 2 set forth several issue areas to set the groundwork for a long-term planning framework for the state's natural gas system. Track 2A identified issues related to gas infrastructure. Track 2B identified issues related to equity, rate design, gas revenues, safety, and workforce. Track 2C identified issues related to data and process.

On October 14, 2021, the assigned Commissioner issued an Amended Scoping Memo and Ruling (October Ruling) setting forth the scope and schedule of Track 2. The October Ruling invited parties to comment on the scope of issues for Track 2. Opening comments[4] were filed on November 2, 2021, and reply comments[5] were filed on November 12, 2021.

On January 5, 2022, the assigned Commissioner issued an Amended Scoping Memo and Ruling (Amended Scoping Memo) taking into account comments on the October Ruling. On January 10, 2022, and January 24, 2022, Commission staff hosted two workshops on topics including Track 2A issues as detailed in the Amended Scoping Memo. On March 1, 2022, the assigned Administrative Law Judge (ALJ) issued a ruling circulating a Track 2 workshop report prepared by Commission staff summarizing the January workshops and

[4] Opening comments were filed by SBUA, SWG, PG&E, SDG&E/SoCalGas, MRP, NRDC, Cal Advocates, CCUE, Green Hydrogen Coalition (GHC), CEJA, Sierra Club, The Greenlining Institute (Greenlining), CAISO, Coalition for Renewable Natural Gas (CRNG), SCE, Indicated Shippers, TURN, SCGC/Protect Our Communities Foundation (POCF) and Center for Accessible Technology (CforAT).

[5] Reply comments were filed by SCE, SCGC/POCF, MRP, Electrochaea Corporation, PG&E, CEJA/Sierra Club/EDF/Greenlining/NRDC, Indicated Shippers, CRNG, and SDG&E/SoCalGas.

inviting party comments. On March 15, 2023, parties filed comments on the Track 2 workshop report.

On May 5, 2022, the assigned ALJ issued a ruling seeking party comments on the Amended Scoping Memo, Track 2A Scoping Questions (b)-(k). Opening comments were filed on June 15, 2022.[6] Reply comments were filed on June 27, 2022.[7]

On March 3, 2023, PG&E filed a *Motion to Reopen Comment Period on Track 2A, Question 2.1(c)(i) to Consider Proposal to Reclassify Certain Transmission Pipelines as Distribution Main Consistent with Changes to Pipeline Safety Regulations*, which the assigned ALJ granted on May 22, 2023. On June 13, 2023, PG&E filed a proposal to update several definitions related to transmission and distribution pipelines and to reclassify 600 miles of PG&E gas transmission pipelines and associated facilities as distribution mains (PG&E proposal). On July 7, 2023, UCAN filed opening comments on PG&E's proposal. On July 17, 2023, PG&E filed reply comments on UCAN's opening comments and UCAN filed reply comments on PG&E's proposal.

On August 1, 2023, the Assigned Commissioner issued a *Phase 2 Scoping Memo and Ruling* (Phase 2 Scoping Memo). The Phase 2 Scoping Memo reordered the Track 2A issues 2.1(b)-(c) into Phase 2, Task 1 issues and the Track 2A issue 2.1(g) was redesignated as a Phase 2, Task 2 issue.

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[6] Opening comments were filed by GHC, CRNG, RMI, NRDC, Central Valley Gas Storage (CVGS), TURN, SCE CAISO, CforAT, EDF, IEPA, Cal Advocates, PG&E, Indicated Shippers, Vistra, SWG, Lodi Gas Storage (LGS)/Wild Goose Storage LLC (WGS), SCGC, SDG&E/SoCalGas, Sierra Club, and CEJA.

[7] Reply comments were filed by MRP, CforAT, CCUE, EDF, SDG&E/SoCalGas, PG&E, SCE, CRNG, Sierra Club/NRDC/CEJA, UCAN, SCGC, Indicated Shippers, and RMI.

1.1. Submission Date

Phase 2 of this matter was submitted on July 17, 2023, with the filing of reply comments on PG&E's proposal.

2. Jurisdiction

Public Utilities (Pub. Util.) Code Section 701 provides that the Commission "may supervise and regulate every public utility in the State and may do all things, whether specifically designated in this part or in addition thereto, which are necessary and convenient in the exercise of such power and jurisdiction." Pub. Util. Code Section 451 provides that each public utility in California must "furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities, . . . as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public."

3. Issues Before the Commission

The Phase 2, Task 1 issues included in the Phase 2 Scoping Memo and addressed in this decision include:

Task 1: Transmission Pipelines[8]

a. What criteria should the Commission use to determine whether aging transmission infrastructure should be repaired or replaced versus being derated or decommissioned when a gas utility requests ratepayer funds?

b. Should the criteria for whether to repair/replace or derate/decommission be based on whether that piece of infrastructure is necessary to meet the utility's design standard as determined in Track 1?

c. What other criteria might be considered?

[8] These issues were included in the Amended Scoping Memo Track 2A issues 2.1(b)-(c).

d. How should the cost to repair or replace the infrastructure be balanced against its reliability benefits?

e. What criteria should be used to determine when declining demand can enable transmission pipelines to be derated or decommissioned without harming reliability?

f. How should the Commission define a transmission pipeline versus a distribution pipeline?

g. What should the regulatory process be for derating a transmission pipeline to a distribution pipeline?

Task 2: Natural Gas Storage Facilities[9]

a. What should be the role of existing natural gas storage facilities as components of gas utilities' infrastructure portfolio?

4. Criteria and Information Requirements to Determine Whether Aging Transmission Infrastructure Should Be Repaired or Replaced Versus Being Derated or Decommissioned When a Gas Utility Requests Ratepayer Funds

This section addresses Phase 2, Task 1 issues (a)-(d). After reviewing party comments, this section adopts criteria and information requirements the gas utilities must address in all future applications that include proposals to repair or replace transmission pipeline infrastructure, starting January 1, 2024. We intend to use these criteria to review all gas utility transmission pipeline infrastructure project applications and related revenue requirement requests after this date, whether contained in general rate case or free-standing applications, and whether or not the project is subject to GO 177.[10] Adoption of clear information requirements and criteria will provide for consistency and thorough Commission

[9] This issue was included in the Amended Scoping Memo as Track 2A issue 2.1(g).

[10] *See* GO 177, available as of August 28, 2023 at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M499/K705/499705854.PDF.

review of transmission projects as the natural gas system changes over the coming decades.

4.1. Background

As discussed in the Phase 2 Scoping Memo, maintenance, repair and replacement costs for transmission pipelines comprise a significant portion of gas infrastructure costs, despite transmission pipelines' relatively limited extent as a percent of all gas infrastructure. Transmission pipelines account for approximately five percent of all pipelines in California but PG&E's revenue requirement request for its gas pipeline transmission system comprised 27 percent of its revenue requirement request in 2023.[11] In the case of SoCalGas, transmission pipelines accounted for 11 percent of that company's total general rate case gas revenue requirement request in 2023.[12] SDG&E's 2023 revenue requirement request for its transmission system in 2023 was $17 million, two percent of its gas revenue requirement.[13] These funds include capital, operations and maintenance, and administrative costs, including costs to implement the federally required Transmission Integrity Management Program (TIMP) as well as Commission-required Pipeline Safety Enhancement Plan (PSEP) programs. A method to potentially reduce costs to the natural gas pipeline system is to identify transmission pipelines that can be derated to distribution pipelines or

[11] Commission staff, "2023 Senate Bill 695 Report" at 83, available as of August 31, 2023 at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2023/2023-sb-695-report---final.pdf. PG&E's backbone and local transmission systems comprised eight percent ($468 million) and 19 percent ($1,052 million), respectively, of PG&E's total 2023 revenue requirement request.

[12] *Id.* at 86. SoCalGas's backbone transmission and local transmission costs accounted for eight percent ($507 million) and three percent ($157 million) of SoCalGas's 2023 GRC revenue requirement request, respectively.

[13] *Id.* at 88.

potentially decommissioned without compromising the safety or reliability of the rest of the system.

4.2. Party Comments

In comments on these topics, multiple parties stress the interdependence of the gas and electricity sectors and urge the Commission to ensure that whatever action is taken does not impair the supply of gas needed for electric generation. PG&E argues that the Commission should not adopt specific repair or replacement criteria but rely instead on general rate case proceedings to make those determinations. PG&E asserts that other important considerations include the need for the infrastructure to serve hard-to-electrify customers, Commission and federal regulatory requirements, urgency to address pipeline integrity or capacity concerns, anticipated capacity benefits, threat elimination, industry best practices, and construction or permitting feasibility.[14] NRDC disagrees with PG&E and argues that repair/replace criteria for transmission pipelines should be determined in this proceeding.

SDG&E/SoCalGas stress that safety and reliability should always be primary concerns. SCGC argues that age alone should not determine whether a pipeline should be replaced. RMI advocates requiring the gas utilities to decommission as much of the gas pipeline system as possible, as fast as possible.

Sierra Club[15] and Indicated Shippers[16] observe that transmission infrastructure should be maintained if it is needed to meet reliability standards.

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[14] PG&E Opening Comments at 2.

[15] Sierra Club Opening Comments at 5.

[16] Indicated Shippers Opening Comments at 4.

Cal Advocates[17] and SCGC[18] state that decisions on whether to repair, replace or derate transmission infrastructure should be based on whether the relevant infrastructure is needed at its current operating pressure to meet the utility's reliability standards. SCGC recommends that pipelines should be periodically evaluated in response to changing demand and reliability standards.

Other criteria mentioned by parties include the need for the pipeline to transport other gaseous fuels such as renewable natural gas (RNG),[19] curtailing customers as an alternative to repair or replacement of pipelines and using the Risk-Spend Efficiency comparison used in Risk Assessment and Mitigation Phase and general rate case filings to determine whether to repair or replace pipelines.[20]

4.3. Prioritization of Reliability and Safety Standards When Determining Whether Aging Transmission Infrastructure Should Be Repaired or Replaced Versus Being Derated or Decommissioned

The primary criteria we intend to use to determine whether aging transmission infrastructure should be repaired or replaced as opposed to being derated or decommissioned when a gas utility requests ratepayer funds is the need for the infrastructure to meet reliability standards.[21] Transmission pipelines are critical to both the reliability of the gas and electric systems. As a result, if a pipeline is needed to meet reliability standards it <u>must</u> be maintained in

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[17] Cal Advocates Opening Comments at 1.

[18] SCGC Opening Comments at 2.

19 CRNG Opening Comments at 4; SDG&E/SoCalGas Opening Comments at 5.

[20] D.18-12-014 directed the large energy utilities to prepare Risk-Spend Efficiency ratios to analyze proposed mitigations to safety risks. D.22-12-027 modified this to instead require the preparation of Cost-Benefit ratios.

[21] *See* D.22-07-002, adopted in Track 1 of this proceeding, and D.06-09-039.

accordance with state and federal safety standards. When a transmission pipeline is no longer needed at its current operating pressure to meet the reliability standards, or for other reasons as described below, it may be considered for decommissioning, or for deration, if consistent with the Pipeline and Hazardous Materials Safety Administration requirements set forth in 49 CFR Part 192 and GO 112-F.[22]

There are several additional reasons that a transmission pipeline may still be needed even if it is not needed at current operating standards to meet reliability standards. A transmission pipeline may be needed to ensure sufficient redundancy in the pipeline system as a whole, including during periods of routine maintenance.[23] Sufficient redundancy may also help protect against gas market volatility since limited capacity to transport gas can impact gas prices.[24] Or, it may be needed to ensure the reliability of the electric system, as observed by several parties.[25]

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[22] *See* Federal Minimum Pipeline Safety Standards, 49 CFR Part 192, available at: https://www.ecfr.gov/current/title-49/subtitle-B/chapter-I/subchapter-D/part-192. (*See also* GO 112-F, available as of August 30, 2023 at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K327/163327660.PDF.)

[23] March 1, 2022 Rulemaking (R.) 20-01-007 Track 2 — Gas Infrastructure Workshop Report at 8-9, available as of August 31, 2023 at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M454/K981/454981991.PDF. For example, three transmission pipelines serve San Francisco even though the city's load can be met with two transmission pipelines. Since pipelines must be periodically taken out of service for required maintenance, the third transmission pipeline is necessary to ensure reliability.

[24] For an example of a price spike event that occurred, in part, due to simultaneous intrastate pipeline outages on the SoCalGas transmission system, *see* "Winter 2017-18 SoCalGas Conditions and Operations Report," Energy Division staff, December 6, 2018, available as of September 26, 2023, at: https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/news_room/newsupdates/2018/winter2017-2018lookbackreportcleanfinal-2018-12-06-v2.pdf.

[25] SCGC Opening Comments at 3.

Another criterion that we may consider when considering the need for a transmission pipeline is the need for the pipeline to transport gaseous fuels other than natural gas. However, we do not see this as an immediately applicable criterion that must be addressed in each utility application or considered by this Commission in all cases, as there has not been enough information presented in this proceeding to date on needs for transmission pipelines to transport gaseous fuels other than natural gas. Utilities may present such information if they believe it relevant to a specific repair or replacement decision.

A pipeline that is no longer needed to meet reliability standards at current operating pressure, provide the redundancy necessary to conduct periodic maintenance, meet state or federal safety requirements, support electric reliability, or serve hard-to-electrify customers should be considered for deration or decommissioning to reduce maintenance costs.

If a pipeline is needed to meet reliability standards or for other reasons, as discussed above, it should be repaired or replaced. The question then becomes whether repair or replacement is the more cost-effective option. We agree with several parties' suggestion that the Commission should primarily base the decision about whether to repair or replace a transmission pipeline on the respective Risk-Spend Efficiency ratio of transmission pipeline proposals (soon to be Cost-Benefit Ratios),[26] as these include a calculation of reliability.

Once it has been determined that a given pipeline is needed for reliability purposes or other reasons as described above, utilities and the Commission may consider other criteria described by PG&E regarding whether a pipeline is better replaced or repaired, namely:

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[26] *See* D.22-12-027.

- Urgency to address pipeline integrity or capacity concerns;
- Anticipated capacity benefits;
- Threat elimination;
- Industry best practices; and
- Construction or permitting feasibility.

Additionally, we agree with SCGC that transmission pipelines may need to be periodically evaluated in response to changing demand and reliability standards. To provide for more robust consideration, however, we defer further consideration of this topic to later phases of this proceeding.

Sierra Club argues that when a transmission pipeline is no longer needed to meet reliability standards, it should not be funded.[27] We have two concerns with this recommendation and do not adopt it. First, regarding reliability, a transmission pipeline that is no longer needed to meet the backbone design standards may still be needed for local reliability. In this case, deration may be more appropriate than decommissioning, and the pipeline would continue to need funding. Secondly, as discussed above and reflected in our adopted criteria, we agree with PG&E that there may be other factors that may cause a given transmission pipeline to still be needed. As a result, gas utilities must be given the flexibility to document the need for specific pipelines as we move forward.

We do not adopt the criteria recommended by the Sierra Club,[28] related to the location of the piece of infrastructure in question related to High Consequence Areas (HCA) because this designation is not relevant to a determination of whether to repair/replace or derate/decommission

[27] Sierra Club Opening Comments at 4.

[28] Sierra Club Opening Comments at 6.

infrastructure. If a transmission pipeline is located in an HCA, the Pipeline and Hazardous Materials Safety Administration (PHMSA) requires additional safety measures; if a transmission pipeline is derated to distribution status, then the HCA designation no longer applies.[29] We do not adopt other criteria suggested by Sierra Club such as the difficulty of repairs or replacement, level of gas throughput, and number and type of customer utilization of the pipeline as these are not high-level screening criteria such as the need for a pipeline to maintain reliability standards and other criteria as discussed above.

We do not adopt SCGC's recommendation that greater use be made of curtailment as an alternative to infrastructure maintenance. This is because the reliability standards adopted in D.22-04-022 specify how often curtailments should statistically occur (*e.g.*, once in 10 years for SoCalGas noncore customers or once in two years for PG&E noncore customers), and this is the appropriate frequency of use of curtailments.

4.4. Adopted Information Requirements for Gas Utility Transmission Infrastructure Funding Requests and Criteria for Commission Review

The full set of our adopted criteria for the Commission to use to determine whether aging transmission infrastructure should be repaired or replaced or whether it is appropriate to consider derating or decommissioning of the transmission pipeline is provided below and in Attachment A.

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[29] *See* PHMSA Fact Sheets on TIMP and DIMP requirements, available as of August 31, 2023 at: https://www.phmsa.dot.gov/pipeline/gas-transmission-integrity-management/gt-im-fact-sheet and https://www.phmsa.dot.gov/pipeline/gas-distribution-integrity-management/gas-distribution-integrity-management-program-dimp.

We intend to use these criteria to review all future gas transmission infrastructure project applications, including those that require a certificate of public convenience and necessity application filing pursuant to GO 177.

To facilitate this review, all gas utility applications for approval of transmission pipeline projects or revenue recovery must provide information to address these criteria, starting January 1, 2024. Gas utilities shall address these criteria in all applications that request approval of transmission pipeline infrastructure projects and/or related revenue requirement requests, including general rate case and free-standing applications and including projects subject to GO 177 and projects not subject to GO 177.

Adoption of clear review criteria will provide for consistency and thorough Commission consideration of transmission projects as the natural gas system changes over the coming decades. Requiring gas utilities to address adopted information requirements in all applications that include requests for approval of transmission pipeline infrastructure supports consistent review and standards.

Adopted Criteria for Repair or Replacement of Aging Transmission Infrastructure Versus Decommissioning or Deration

1. If the gas transmission infrastructure is needed at its current operating pressure to meet reliability standards,[30] meet state or federal safety requirements, support electric reliability, serve hard-to-electrify customers, or provide for the redundancy needed to allow for routine maintenance, it should be repaired or replaced.[31] An optional consideration may be the need for a transmission pipeline to carry gaseous fuels other than natural gas.

[30] *See* D.22-07-002 and D.06-09-039.

[31] Construction and permitting feasibility may also be considered. Projects with extremely high costs and limited duration of reliability benefits should be given extra scrutiny.

2. The pipeline system as a whole, and replacement or repair projects, must meet safety and reliability standards.

3. If the criteria in #1 are met, consider the Risk-Spend Efficiency or Cost-Benefit Ratios to determine whether repair or replacement is the best option.

5. Criteria to Determine When Declining Demand Can Enable Transmission Pipelines to Be Derated or Decommissioned Without Harming Reliability

This section considers party comments on the Phase 2, Task 1 scoping issues (e)-(g) regarding transmission pipelines. These issues address the criteria that should be used to determine when declining demand can serve as the basis for transmission pipelines to be derated or decommissioned without harming reliability as well as what the regulatory process should be for derating a transmission pipeline to a distribution pipeline.

This section adopts criteria for when gas utilities must consider transmission pipelines for derating or decommissioning. It requires gas utilities to provide an information-only submittal describing planned transmission pipeline derations.

5.1. Party Comments

In comments regarding criteria to determine when declining demand can enable transmission pipelines to be derated or decommissioned without harming reliability, IEPA, Vistra and CAISO stress the need to maintain adequate gas infrastructure to serve electric generator load. IEPA recommends considering whether the infrastructure will be needed to transport other gaseous fuels within a reasonable time frame.

NRDC recommends the Commission require utilities to file Tier 2 advice letters when they identify transmission pipeline segments that are suitable for derating to distribution pressures. NRDC recommends requiring utilities to submit gas system transition plans that include opportunities to derate transmission pipelines.

PG&E notes that federal pipeline safety code has no regulatory requirements for downrating pipelines as this generally reduces pressure which reduces risks,[32] that each pipeline segment poses unique considerations, and that pipelines can be derated if existing and future loads do not require the transmission asset. PG&E states that it already studies system impacts prior to derating a significant asset. As a result, PG&E opposes NRDC's recommendation regarding Tier 2 advice letters, stating that PG&E routinely derates and decommissions assets without the need for regulatory filings. However, PG&E generally supports NRDC's recommendation that consideration of derating be included in long-term gas plans.

SDG&E/SoCalGas emphasize the need to maintain reliability and resiliency and to consider the financial and ratemaking consequences of derating or decommissioning assets, particularly for lower-income customers. CforAT agrees that proceeding with some caution with regard to rate impacts and reliability is important.

Southwest Gas notes that if derating a pipeline will lower its operating pressure to less than 20 percent of Specified Minimum Yield Strength (SMYS), the reclassification would be captured in the Southwest Gas' annual reporting required pursuant to the Commission's GO 112-F. Southwest Gas also notes that if the project meets the requirements of GO 112-F, Section 125, a Proposed Installation Report would be filed with the Commission.[33]

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[32] PG&E, March 15, 2022 comments on March 1, 2022 R.20-01-007 Track 2 — Gas Infrastructure Workshop Report.

[33] Southwest Gas March 15, 2022 comments.

EDF recommends utilities be clear about which customers are on a transmission pipeline planned for derating or decommissioning. EDF comments that the utility should demonstrate that a distribution pipeline resulting from the deration of a transmission pipeline will be "used and useful."

Cal Advocates recommends that the Commission require a utility to establish that a transmission pipeline poses low risk to life and safety, by demonstrating that derated segments would have no HCAs or Medium Consequence Areas (MCA) within the potential impact circle at the derated maximum allowable operating pressure (MAOP). Cal Advocates recommends this because "parts of the utilities' natural gas systems pre-date the implementation of . . . PHMSA safety requirements in the 1970s and have been allowed to operate at historical pressures under 49 CFR 192 § 619(c)."[34]

CRNG recommends that utilities should assess whether the derated pipeline would have the pressure and capacity to carry RNG from a future nearby supply.

5.2. Transmission Pipelines That Are No Longer Needed at Total Nominal Capacity to Meet Reliability Standards Must Be Considered for Derating or Decommissioning

As reviewed in the Phase 2 Scoping Memo, maintenance, repair and replacement costs for transmission pipelines comprise a significant portion of gas infrastructure costs despite their relatively limited extent as a percent of all gas infrastructure. Therefore, to provide for potential cost savings that can be passed on to ratepayers, we require that gas utilities consider for derating or decommissioning all transmission pipelines that are no longer needed at total

[34] Cal Advocates Opening Comments at 3.

nominal capacity to meet reliability standards, state or federal safety requirements, ensure electric reliability, serve hard-to-electrify customers, or provide for the redundancy needed to allow for routine maintenance. If a transmission pipeline is not needed at its total nominal capacity[35] but cannot deliver sufficient fuel to meet demand at less than 20 percent SMYS, then it should not be considered for deration. Derating a transmission pipeline from its total nominal capacity would reduce its capacity to transport gas.

When considering derating a transmission pipeline, the utility should determine if the planned derating would be sufficient for the pipeline to be reclassified as a distribution pipeline per PHMSA 49 CFR Part 192, Section 192.3 definitions and GO 112-F.[36] To maintain safety, utilities must in all instances comply with PHMSA requirements such as 49 CFR Part 192, Section 193 definitions and this Commission's GO 112-F.[37] Section 6 below further discusses recently updated PHMSA definitions.

We adopt the following criteria and regulatory review process for transmission pipeline derating:

1. Utilities must consider for derating or decommissioning all transmission pipelines that are no longer needed at total nominal capacity to meet reliability design standards or state or federal safety requirements, to ensure electric reliability, to serve hard-to-electrify customers, or to

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[35] Total nominal capacity is defined as a measure of the amount of gas that a pipeline is rated to transport. For a discussion of capacity and other gas industry terms, *see* PG&E's "Gas Industry Glossary," available as of August 18, 2023 at: https://www.pge.com/pipeline/library/doing_business/glossary/index.page.

[36] These include requirements regarding MAOP, operating pressure, percent SMYS, diameter, length, class location, and capacity. (*See* March 1, 2023 workshop report, Safey and Enforcement Division (SED) presentation, Panel 3 at Section 4.3.1, available as of August 15, 2023 at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M454/K981/454981991.PDF.)

[37] *See* D.15-06-044, which most recently modified GO 112-F.

provide for the redundancy needed to allow for routine maintenance.

2. If a transmission pipeline is not needed at its total nominal capacity but cannot deliver sufficient fuel to meet demand at less than 20 percent SMYS it should not be considered for deration.

3. Before gas assets are derated, replacement energy sources must be built and operational or demand must have declined sufficiently to avoid the system falling below reliability standards or otherwise losing the ability to meet local customers' energy needs.

4. Utilities must notify the Commission of planned derations in an information-only submittal[38] provided at least 30 days prior to executing a planned transmission pipeline deration.

5. Utilities must serve the information-only submittals to parties to R.20-01-007 and any subsequent long-term gas planning proceeding.

6. The information-only submittal must:

    a. Provide information about each transmission pipeline to demonstrate that it is no longer needed at total nominal capacity;

    b. Demonstrate that the new distribution pipeline is needed to serve customers;

    c. Summarize the anticipated rate impacts of the planned deration.

7. The utilities must establish mechanisms to track any changes in transmission pipeline work plans and revenue requirements adopted in a general rate case. If a utility deviates from these approved plans or revenue requirement it must notify the Commission and parties to

[38] *See* GO 96-B at Section 3.9 and Section 6, available as of August 31, 2023 at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M023/K381/23381302.PDF#page=17.

> R.20-01-007, and any successor proceeding, via an information-only submittal provided no later than 60 days after the work is completed.

A few other considerations merit discussion here. First, we emphasize that the regulatory process for derating transmission pipelines we adopt here does not preclude gas utilities from reducing the operating pressure of any of their pipelines for safety or operational reasons at their discretion. This addresses the concerns raised by PG&E regarding the impact of any new requirement on utilities' existing processes.

Second, as recommended by NRDC, PG&E, the Sempra companies, and MRP, we may in later phases of this proceeding consider the need for an overall strategy for the derating or decommissioning of transmission pipelines. What we adopt today is potentially a transitional step to a more comprehensive process.

Regarding decommissioning, GO 112-F and 49 CFR Part 192, Section 192.727 set forth regulatory and safety requirements when utilities abandon, deactivate or decommission transmission pipelines. These requirements are sufficient at present to both inform the Commission and parties of the relatively infrequent occasions when gas utilities decommission transmission pipelines. As warranted by declines in demand, we may consider modifications to these procedures in a later phase of this or a subsequent long-term gas planning proceeding.

Third, while we agree with EDF's recommendation that the utility be clear about customers on a transmission pipeline proposed for derating, we do not require any changes in existing utility practices regarding informing customers of planned deratings at this time.[39] This is because detailed cost allocation questions and potential rate adjustments stemming from transmission pipeline deratings will be considered in a later phase of this proceeding, not in a piecemeal fashion in response to the information-only submittals. Overall, deration of transmission pipelines will reduce costs for all customers, and this is the primary consideration in the requirements we adopt here. We also do not require the utilities to report the individual customers impacted or the total number of customers affected by a transmission pipeline derating in the information-only submittal requirement adopted here as this could inadvertently reveal confidential customer information and is not necessary.

Fourth, we do not adopt EDF's recommendation that we require the utilities to demonstrate that a distribution pipeline resulting from the deration of a transmission pipeline will be "used and useful." Nor do we require the utilities to consider non-pipeline alternatives when identifying transmission pipelines for deration. A transmission pipeline in use, *i.e.*, "used and useful," for which pressure may be decreased to increase safety margins is appropriate for consideration to derate to a distribution pipeline. Appropriate operational and integrity management standards for distribution pipelines will then be applied to the derated segment. However, there is no additional need to demonstrate usefulness of the derated pipeline; the deration in this case this is simply an action to minimize maintenance costs safely.

A more appropriate forum for consideration of potential non-pipeline alternatives for transmission pipelines will be in the long-term gas planning

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[39] For an example of a current customer notification approach, *see* PG&E's "Gas Transmission Pipe Ranger, Derating of the Topock Compressor Station" available as of August 18, 2023 at: https://www.pge.com/pipeline/news/newsdetails/index.page?title=20180309_2174_news.

process that we will initiate later in this proceeding. Due to the centrality of transmission pipelines to the gas system, we expect such opportunities to be rare in the near- to mid-term. The information-only submittal process we adopt here to add transparency to transmission pipeline deratings is also not an appropriate vehicle for considering non-pipeline alternatives.

Fifth, we do not adopt Cal Advocates' recommendation that the Commission require a utility to demonstrate that derated segments would have no HCAs or MCAs within the potential impact circle and the derated MAOP. This suggestion is redundant if a pipeline stays a transmission pipeline and unnecessary if it is derated. PHMSA requires operators to identify transmission pipelines located within HCAs and MCAs. Under most circumstances, derating a transmission pipeline would reduce the pressure and thus the risk, and the pipeline would therefore no longer need to adhere to these PHMSA requirements. Additionally, D.11-06-017 ended the PHMSA "grandfathering" of older transmission pipelines.[40] Existing Commission requirements set forth in GO 112-F and Distribution Integrity Management Program (DIMP) procedures will be required of the new distribution pipeline segment.

Sixth, we do not adopt CRNG's recommendation that we require utilities to assess whether the derated pipeline would have the pressure and capacity to carry RNG from a future nearby supply. Although the utilities may consider this issue as an optional consideration, we do not adopt this as a mandatory requirement at this time. Future supply and uses of RNG remains unclear at this time, whereas cost savings can be realized in the short term from deration of

[40] D.11-06-017 at 18. New PHMSA rules contained in 49 CFR Part 192.3 ended grandfathering at the national level.

transmission pipelines. Specific proposals for use of transmission pipelines to transport RNG can be considered as they arise.

Seventh, we disagree with Southwest Gas that the current regulatory process whereby utilities report derating of transmission pipelines in annual reports required pursuant to GO 112-F or in Proposed Installation Reports required in GO 112-F is sufficient. Although transmission pipeline derations may be inferred in the annual reports, the information is not typically clearly presented, nor are these reports typically publicly posted. The process we adopt today will add transparency to transmission pipeline derating decisions in a way that is not possible if this information is only included in technical annual or other reports.

Eighth, there may be limited instances where a transmission pipeline is not needed at its total nominal capacity but cannot deliver sufficient fuel to meet demand at less than 20 percent SMYS. Such pipelines should not be considered for deration. As relevant, we may consider more systematically identifying such instances and potential alternative approaches to address them in the long-term planning process anticipated for later in this proceeding.

Finally, we disagree with NRDC that a Tier 2 advice letter process is the appropriate manner to inform the Commission and parties to R.20-01-007 of planned and completed derations. As pointed out by PG&E, the regulatory process we adopt today must not disrupt existing utility derating and decommissioning processes and is intended to supplement, not replace our current reporting processes surrounding derating transmission pipelines.[41] We

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[41] GO 112-F requires utilities to report deratings or reclassifications of pipelines in annual reports. If the project meets the requirements of GO 112-F, Section 125, a Proposed Installation Report must be filed with the Commission.

adopt here an approach for which additional transparency is the primary benefit. An information-only submittal may not be protested and is effective upon submittal and thus will not disrupt utility processes.

6. Defining a Transmission Pipeline Versus a Distribution Pipeline

The Phase 2, Task 1 scoping issue (f) asks how the Commission should define a transmission pipeline versus a distribution pipeline. This section does not adopt a single Commission definition of these terms. Instead, this section reinforces that gas utilities must continue to comply with Commission GO 112-F requirements to align with PHMSA definitions of these terms as most recently set forth in 49 CFR Part 192.3 or as amended, if relevant, in the future. This section also approves PG&E's proposal to update its definitions of "transmission [pipe]line" and "distribution center," resulting in the reclassification of approximately 600 miles of PG&E transmission pipeline as distribution pipeline.

6.1. Party Comments

Regarding the question of how the Commission should define a transmission pipeline versus a distribution pipeline, SDG&E/SoCalGas explain that they apply a Commission-approved functional definition to pipeline assets such that any pipeline that connects a source of natural gas to a pipeline that distributes the gas to customers is considered a transmission pipeline.[42] In addition to this, SDG&E/SoCalGas indicate that federal guidelines define a transmission pipeline to be any pipeline that operates at greater than 20 percent of SMYS and SDG&E/SoCalGas comply with this requirement.

PG&E argues that the Commission should utilize the transmission pipeline definition contained in 49 CFR Part 192.3. However, PG&E also stresses the

[42] SDG&E/SoCalGas Opening Comments on Track 2A Scoping Questions at 17.

individual nature of each utility's decisions regarding derating or decommissioning transmission pipelines as this relates to a utility's obligation to serve.

Southwest Gas points to an ambiguity in the then-current federal PHMSA definition of a "distribution center" which makes it difficult to determine which of its pipelines are transmission pipelines and which are distribution pipelines, a problem also noted by SCGC.

Cal Advocates notes that PHMSA has defined transmission and distribution pipelines under 49 CFR Part 192.3. Cal Advocates observes that 49 CFR Part 192 Subpart O is intended to provide assurance that pipelines are operating safely under the transmission integrity management regulations. Cal Advocates asserts that in cases where transmission pipelines pose a low risk to life and safety, derating from transmission to distribution pipelines may be appropriate.

NRDC states that the utilities should follow the PHMSA definitions for transmission and distribution pipelines and adopt a standard interpretation of these definitions.

6.2. Pacific Gas and Electric Company Proposal

On June 13, 2023, PG&E filed the PG&E proposal identified in Section 1 above seeking to update PG&E's definition of "transmission pipeline." PG&E's proposal explains that PG&E's current definition of "transmission pipeline" was adopted in D.16-06-056 and PG&E's proposed changes would better align PG&E's approach with recent changes in a key PHMSA rule, portions of which became effective May 24, 2023. Specifically, PG&E proposes to adopt the 2023 PHMSA definitions of "transmission [pipe]line" and "distribution center" provided in 49 CFR Part 192.3 (also referred to as the PHMSA "Mega Rule

Part 2").[43] PG&E notes that prior to the PHMSA Mega Rule Part 2 definitional updates, PHMSA had not defined a "distribution center." This allowed PG&E to implement a conservative interpretation of the definition of transmission pipeline such that PG&E's approach included pipelines that most other utilities define as distribution. PG&E's proposal also seeks to revise PG&E's definition of "large volume customer" (not defined in 49 CFR Part 192.3) to better align with definitions adopted by other California operators.

Approval of PG&E's pipeline reclassification proposal would result in the reclassification of approximately 600 miles of PG&E gas transmission pipelines and associated facilities as distribution mains. Specifically, PG&E's proposed new definition of "distribution center" would allow for lateral pipelines operating above 60 pounds per square inch (psig) but under 20 percent SMYS to be reclassified as distribution rather than transmission pipelines, assuming all remaining requirements are met.

PG&E's proposal would change PG&E's pipeline definitions to reflect the PHMSA Mega Rule Part 2 as follows:

> **Distribution Center**
>
> PG&E designates a Distribution Center as the point where a Transmission [Pipe]line changes function to a Distribution Line that primarily serves non-large volume customers, typically the downstream side of a component with a function such as pressure regulation, lateral volume reduction (tap or tee), or metering, after which gas flows into a line that

[43] The PHMSA definition refers to "transmission line" not "transmission pipeline," but these terms have equivalent meanings. (*See* 49 CFR Part 192.3.)

> continuously has a downstream maximum allowable operating pressure (MAOP) of less than 20 [percent] SMYS.[44]
>
> **Transmission [Pipe]line**
>
> PG&E designates a Transmission [Pipe]line as a pipeline or connected series of pipelines, other than a gathering line, that meets ANY of the following criteria:
>
> (1) Transports gas from another transmission [pipe]line, gathering line, or storage facility to a Distribution Center, Storage Facility, or Large Volume Customer that is upstream of a Distribution Center.
>
> (2) Operates at or above a hoop stress of 20 [percent] SMYS, or is upstream of a segment of pipe operating at or above a hoop stress of 20 [percent] SMYS.
>
> (3) Transports gas within a storage field.
>
> (4) Is voluntarily designated as a transmission pipe.[45]

The PG&E Proposal would also update PG&E's definition of "large volume customer" as follows:

> **Large Volume Customer**
>
> Large Volume Customer means a customer served by PG&E gas facilities which have the rated capability of delivering 10 million cubic feet per day (MMcf/d) or more. PG&E designates rated capacity as the maximum flow rate through the station that serves the Large Volume Customer.

PG&E proposes to implement site-specific procedures in conformance with and to implement these definitions within 12-18 months following the approval of its proposal or a final 2023 general rate case decision. PG&E states

[44] PG&E Proposal at 3. Currently, PG&E defines "Distribution Center" to be "at the inlet fire valve of a regulator station, where gas pressure is reduced to 60 psig or less primarily serving end-use customers. All pipeline upstream of the Distribution Center is classified as transmission." For consistency, we refer to PG&E's proposal as affecting "transmission pipelines" not "transmission lines," although these terms have equivalent meanings.

[45] *Id.* at 4.

that all reclassified pipelines will have an MAOP that is less than 20 percent of the pipe's SMYS.

PG&E states that after implementing the new definitions, the reclassified pipelines will be subject to DIMP rather than TIMP integrity management requirements, which should reduce integrity management costs. However, PG&E states it will continue to apply leak surveys to the reclassified pipelines at schedules relevant for transmission pipelines.[46]

PG&E states that a customer's current tariffed rate schedule is based on delivery pressures. PG&E states that rates of customers who receive gas delivery from the applicable pipelines will not therefore be impacted by the reclassification as existing delivery pressures will not be altered. PG&E indicates that adoption of the modified definitions will result in lower overall system costs because PG&E will no longer need to maintain the pipelines in accordance with TIMP requirements, which are costly, and instead will maintain them consistent with the DIMP, which is less costly. PG&E states that it will provide information on the specific cost reduction benefits and other impacts of its proposal in a future general rate case application or other rate-setting application.

PG&E requests that any Commission order granting PG&E's reclassification proposal include the ability for PG&E to modify its pipeline classifications going forward based on regulatory changes and interpretations.

6.3. Party Comments on Pacific Gas and Electric Company Proposal

Only UCAN commented on PG&E's proposal, although many of UCAN's comments do not address PG&E's proposal specifically. UCAN asserts that PG&E does not provide assurances that the reclassified pipelines will not operate

[46] PG&E Response to ALJ Ruling at 7.

in excess of 60 psig and PG&E did not provide information regarding whether the pipelines in question have been hydrostatically tested and are up to date on inspections, including whether accurate records about the pipelines have been maintained. UCAN contends that PG&E should have set forth a full schedule of standards and analysis of the pipelines over the 12-to-18-month implementation period proposed by PG&E. UCAN also notes PG&E's serious history of safety incidents, including being found guilty of criminal negligence, involuntary manslaughter, and having received multi-billion-dollar fines due to safety incidents.

6.4. Defining a Transmission Pipeline Versus a Distribution Pipeline

We do not adopt a single Commission definition of the terms "transmission pipeline" and "distribution pipeline." Instead, we reinforce that the gas utilities must continue to comply with Commission GO 112-F requirements to align with PHMSA definitions of these terms as most recently set forth in 49 CFR Part 192.3 or as amended, if relevant, in the future.

We agree with NRDC that the utilities should follow the definitions of key terms consistent with 49 CFR Part 192.3. The Commission's GO 112-F states that its requirements are adopted *in addition* to 49 CFR Parts 191-193 and Part 199 and do not supersede PHMSA pipeline safety regulations.[47] Because compliance with PHMSA regulations is already required by GO 112-F, it is not necessary for this Commission to adopt further definitions of transmission and distribution

[47] GO 112-F at 1, available as of August 15, 2023 at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K327/163327660.PDF.

lines. PHMSA defines a "distribution pipeline" as a "pipeline other than a gathering or transmission [pipe]line."[48]

The Commission, through certifications and agreements with PHMSA, has adopted and continues to enforce federal natural gas pipeline safety regulations on all gas utilities that operate intrastate gas pipelines in California.[49] The Commission's GO 112-F automatically incorporates these regulations and any applicable revisions.

6.5. Pacific Gas and Electric Company Proposal Is Reasonable and Is Approved

We find reasonable PG&E's proposal to update its definitions of "distribution center," "transmission [pipe]line," and "large volume customer" and approve these changes.[50] These changes are consistent with the PHMSA Mega Rule Part 2 definitional changes that became effective on May 24, 2023. In its proposal, PG&E states that it sought Commission approval to make these changes because the current definitions that PG&E applies were adopted in D.16-06-056 and therefore did not reflect the recent PHMSA updates. Approving PG&E's request is important because it will result in lower overall system costs, which will benefit customers.

We approve PG&E's reclassification of some 600 miles of transmission pipeline as distribution pipeline. Applying these new definitions will result in PG&E's reclassification of a significant amount of its transmission pipeline as

[48] 49 CFR Part 192.3.

[49] March 1, 2022 workshop report, SED presentation, Panel 3 at Section 4.3.1, available as of August 15, 2023 at:
https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M454/K981/454981991.PDF.

[50] For consistency, we have modified PG&E's proposed definition of "transmission line" to refer to "transmission pipeline" throughout this decision. PG&E may apply its approved definition to either term as they have equivalent meanings.

distribution pipeline and will lead to lower overall system costs. PG&E has stated that it will maintain all pipeline segments that are reclassified from transmission to distribution in accordance with leak survey requirements for transmission pipelines but will transition these pipelines from the more expensive TIMP to the less costly DIMP, which we also approve.

PG&E's actions to reclassify 600 miles of transmission pipeline to distribution pipeline bring the utilities' interpretations of the definitions of these terms into closer alignment. This is because Commission requirements regarding pipeline definitions are addressed in GO 112-F. GO 112-F permits differences in utilities' interpretations of the functional definition of transmission pipeline in part due to the prior ambiguity of the terms "distribution center," and "large volume customer," which PHMSA had not defined prior to adopting the Mega Rule Part 2.[51]

PG&E's proposal indicates that authorizing PG&E to implement the updated definitions will lead to lower overall costs for ratepayers but will not change affected customers' tariffed rate schedule. This is because customers' distribution and transmission tariffed gas rate schedules are based on delivery pressures and PG&E does not intend to change delivery pressures for affected customers. PG&E should provide specific information on the cost reduction benefits and other impacts of its proposal in a future general rate case application or other rate-setting application.

We approve PG&E's proposal to implement site-specific procedures in conformance with its updated definitions in the 12-18 months following issuance

[51] March 1, 2022 workshop report, SED presentation, Panel 3 at Section 4.3.1, available as of August 15, 2023 at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M454/K981/454981991.PDF.

of this decision or a final 2023 general rate case decision, which ever comes last. Additionally, we authorize PG&E to further modify its pipeline classifications going forward based on regulatory changes and interpretations. We agree with PG&E that authorizing this is consistent with other operational changes that PG&E may make for safety, compliance and/or process improvement reasons. PG&E shall report any such reclassifications in an applicable general rate case or ratesetting application.

As noted above, UCAN was the only party to oppose the PG&E proposal. UCAN. However, we disagree with UCAN that PG&E should have provided additional assurances that the reclassified pipelines will not operate in excess of 60 psig. As stated by PG&E, PG&E's implementation of the Mega Rule Part 2 allows for some PG&E pipelines operating above 60 psig but under 20 percent SMYS to be reclassified as distribution rather than transmission pipelines. PG&E's proposal indicates that all pipelines to be reclassified currently operate under 20 percent SMYS and will continue to do so.

We disagree with UCAN that PG&E should have provided information regarding whether the pipelines in question have recently been hydrostatically tested because information related to hydrostatic testing is already provided to the Commission under existing PSEP reporting requirements.[52] We disagree with UCAN that PG&E should have provided information on whether inspections of the pipeline are up to date or that accurate records about the pipelines have been maintained because PG&E is required to inspect its transmission pipelines under the TIMP integrity management program and

[52] D.12-12-030 at 86.

49 CFR Part 192.947 stipulates specific recordkeeping requirements for all pipeline operators.

We disagree with UCAN that PG&E should have set forth a full schedule of standards and analysis of the pipelines over the 12-to-18-month implementation period proposed by PG&E. It is reasonable for PG&E to develop the specifics of its implementation process subsequent to Commission approval of its proposal.

Finally, we disagree with UCAN that PG&E's serious history of safety incidents *a priori* signifies that PG&E's proposal does not protect public safety. The Commission remains mindful of PG&E's history and continues to be committed to maintaining and improving pipeline safety. The reclassified pipelines will continue to be subject to appropriate integrity management and pipeline maintenance with Commission oversight. Moreover, the PHMSA Mega Rule Part 2 was promulgated to improve public safety. PG&E's proposal aligns with this PHMSA rule since the reclassified pipelines will have an MAOP that is less than 20 percent of the pipe's SMYS, which reduces the likelihood of a pipeline rupture.

7. The Role of Existing Natural Gas Storage Facilities as a Component of Gas Utilities' Infrastructure Portfolios

The Phase 2, Task 2(a) scoping issue asks: what should be the role of existing natural gas storage facilities as a component of gas utilities' infrastructure portfolio? This section finds that natural gas storage facilities are necessary for reliability and cost management. This decision does not address issues related to the Aliso Canyon gas storage facility, which are addressed in Investigation (I.) 17-02-002.

7.1. Background

As described in the Phase 2 Scoping Memo, there are eleven natural gas storage facilities in California. SoCalGas owns and operates four natural gas storage facilities at Aliso Canyon, Honor Rancho, La Goleta, and Playa Del Rey. PG&E owns and operates natural gas storage facilities at McDonald Island and Los Medanos.[53] Independent storage providers own and operate four other natural gas storage facilities in Northern California — WGS, Gill Ranch Storage,[54] CVGS, and LGS. On July 18, 2023, PG&E filed an application requesting Commission approval of its proposed sale of Pleasant Creek Storage, and this facility is not currently operational.[55] The Commission is considering whether the Aliso Canyon gas storage facility continues to be needed in I.17-02-002.

7.2. Party Comments

SDG&E/SoCalGas note that in order to ensure that natural gas is affordable and reliable it must be stored to be available during periods of peak demand. Reflecting findings of a 2018 California Center for Science and Technology (CCST) report[56] required by the state legislature, SDG&E/SoCalGas assert that the potential risks associated with underground storage are manageable. PG&E concurs with this analysis.

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[53] PG&E announced the sale or its Pleasant Creek natural gas storage field in 2020.

[54] PG&E maintains a 25 percent ownership in this facility.

[55] D.19-09-025 at Ordering Paragraph (OP) 42 authorized PG&E to sell or decommission this facility. PG&E filed Application 23-07-007 on July 18, 2023, requesting Commission approval to sell the facility to Pleasant Creek Gas Storage Holdings, LLC and eCORP Natural Gas Storage Holdings, LLC.

[56] CCST (2018), "Long Term Viability of Underground Natural Gas Storage in California: An Independent Review of Scientific and Technical Information," available as of August 15, 2023, at: https://ccst.us/wp-content/uploads/Full-Technical-Report-v2_max.pdf.

SCE notes that natural gas use is projected to decline at a relatively uniform and slow pace and asserts that the use of natural gas storage facilities will decline in tandem. TURN notes that prior investments levels in making natural gas storage facilities safe should be considered.

SCGC notes that natural gas storage facilities are necessary to meet winter demand. Indicated Shippers note that natural gas storage assets play a crucial role in protecting customers from reliability issues and adverse rate impacts in both the gas and electricity sectors.

NRDC and Sierra Club urge the Commission to minimize reliance on stored gas. Vistra, LGS/WGS, and CVGS all emphasize the critical importance of natural gas storage facilities to gas reliability and affordability. CRNG and GHC urge the Commission to consider converting natural gas storage facilities into RNG or hydrogen storage facilities.

7.3. Gas Storage Is Critical to System Reliability

We agree with party comments that natural gas storage facilities are needed for sufficient quantities of natural gas to be available during periods of peak demand to support reliability and affordability.

This finding is compatible with California's work to address safety risks in the aftermath of the October 2015 Aliso Canyon gas leak. California Geologic Energy Management Division (CalGEM) has jurisdiction over ensuring the safe operations of underground gas storage facilities alongside PHMSA. Subsequent to the 2015 Aliso Canyon gas leak, CalGEM developed and now applies more stringent regulations for California's natural gas storage facilities. These regulations went into effect October 1, 2018 and require that all gas storage wells be converted to tubing-only flow[57] within seven years and that storage providers conduct mechanical integrity and pressure testing on each well every 24 months unless a different testing schedule is proposed by the storage provider in its Risk Management Plan and approved by CalGEM. Investments to meet these stringent standards were funded by revenues collected from ratepayers. These investments represent ratepayer assets that continue to have costs associated with them but that also support affordability.

Natural gas storage facilities are necessary to meet winter demand. The Commission opened I.23-03-008 in March 2023 to investigate gas price spikes in California occurring during November 2022 through January 2023, with preliminary analyses implicating low storage inventories as a contributing driver.[58] Natural gas storage facilities play a crucial role in protecting customers from reliability issues and adverse rate impacts in the electricity and the gas sectors.

In sum, natural gas storage facilities are necessary for natural gas reliability and cost management.[59]

Our findings in this area are supported by the 2018 CCST report discussed during the Track 1 workshop in this proceeding.[60] The CCST report finds that:

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[57] Conversion of wells to tubing-only flow limits how much gas can flow within a single well and provides dual-barrier protection to the well tube.

[58] Order Instituting Investigation on the Commission's Own Motion into Natural Gas Prices During Winter 2022-2023 and Resulting Impacts to Energy Markets at 1, discussing U.S. Energy Information Administration analysis, and at 6-8 regarding differences in storage inventory levels in Southern and Northern California between 2021-2022 and 2022-2023.

[59] Pleasant Creek storage field is not currently operational. D.19-09-025 at OP 42 authorized PG&E to sell or decommission this facility.

[60] Track 1A and Track 1B Workshop Report at 24-25, available as of August 15, 2023 at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M348/K035/348035848.PDF.

- California's energy system needs underground natural gas storage for reliability purposes, particularly to meet winter peak daily demand driven by customer heating needs.[61]
- Gas storage is needed to respond to the intermittency of electric generation and the need may increase as more renewables are added to the grid.[62]
- While the need for underground gas storage may be reduced in the coming decades, there are no practical and cost-effective solutions that would significantly mitigate the need for gas storage.[63]
- The risks associated with underground gas storage can be managed and, with appropriate regulation and safety management, may become comparable to risks found acceptable in other parts of the California energy system.[64]

On August 31, 2023, the Commission adopted D.23-08-050, which increased the interim storage limit of working gas in the Aliso Canyon gas storage facility to 68.6 billion cubic feet. The Commission is considering a framework in I.17-02-002 to reduce or eliminate reliance on the Aliso Canyon gas storage facility.[65] As a result, the Aliso Canyon gas storage facility is not addressed in this decision.

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[61] CCST (2018), "Long Term Viability of Underground Natural Gas Storage in California: An Independent Review of Scientific and Technical Information" at 496.

[62] *Id.* at 504.

[63] For example, the CCST report discusses the costs of alternatives to gas storage, such as adding more pipelines but estimates the costs to be approximately $15 billion in capital expenditures. *Id.* at 537.

[64] CCST (2018), "Long Term Viability of Underground Natural Gas Storage in California: An Independent Review of Scientific and Technical Information: Executive Summary" at 6.

[65] A staff proposal distributed in I.17-02-002 outlines the resources that might replace the services provided by Aliso Canyon, how progress towards closure might be assessed, and what rate of change would be necessary to meet a specified target closure date. (*See* "Aliso Canyon I.17-02-002: Staff Proposal for Portfolio and Next Steps," September 23, 2022, available as of

8. Comments on Proposed Decision

The proposed decision of ALJ Cathleen A. Fogel in this matter was mailed to the parties in accordance with Pub. Util. Code Section 311 and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on ____________________, and reply comments were filed on ____________________ by ____________________.

9. Assignment of Proceeding

Commissioner Karen Douglas is the assigned Commissioner and Cathleen A. Fogel is the assigned ALJ in this proceeding.

Findings of Fact

1. The natural gas and electric sectors are interdependent.

2. Natural gas transmission pipelines are critical to the reliability of the gas and electric systems.

3. Transmission pipelines must be maintained in accordance with state and federal safety standards as long as they are needed to meet reliability standards.

4. Decisions on whether to repair or replace as opposed to derating or decommissioning transmission infrastructure should primarily be based on whether the relevant infrastructure is needed at its current operating pressure to meet reliability standards.

5. Other key criteria include ensuring sufficient redundancy in the pipeline system as a whole to allow for routine maintenance, ensuring electric reliability, meeting state or federal safety requirements and serving hard-to-electrify customers.

August 10, 2023, at:
https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M497/K170/497170154.PDF.)

6. Consideration of the need for a transmission pipeline to transport gaseous fuels other than natural gas is not an immediately applicable criterion that must be addressed in each utility application for Commission review of a transmission repair or replacement project, but utilities may include such information as an optional consideration.

7. A transmission pipeline that is no longer needed to meet backbone design standards may still be needed for local reliability.

8. If a transmission pipeline is needed at its current operating pressure to meet reliability standards, meet state or federal safety requirements, support electric reliability, serve hard-to-electrify customers, or provide for the redundancy needed to allow for routine maintenance, the Risk-Spend Efficiency ratio or Cost Benefit Ratios required in D.22-12-027 and D.18-12-014, should be considered to determine whether repair or replacement of the pipeline is the best option.

9. Adoption of clear information requirements and criteria will provide for consistency and thorough Commission review of transmission projects as the natural gas system changes over the coming years.

10. Requiring gas utilities to address the adopted information requirements in all applications that include requests for approval of transmission infrastructure will support consistent standards and review.

11. The pipeline system as a whole, and replacement or repair projects, must meet safety and reliability standards.

12. Maintenance, repair and replacement costs for transmission pipelines comprise a significant portion of gas infrastructure costs, despite their relatively limited extent as a percent of all gas infrastructure in miles.

13. Derating a transmission pipeline reduces overall customer costs.

14. Derating a transmission pipeline reduces pressure within the pipeline and thus reduces risk.

15. The derating process adopted in this decision will add transparency to transmission pipeline derating decisions and should not disrupt existing utility derating and decommissioning processes.

16. PG&E's proposal seeks to update PG&E's definition of "transmission pipeline" and other terms to better align them with recent changes adopted in the PHMSA Mega Rule Part 2, portions of which became effective May 24, 2023.

17. Approval of PG&E's pipeline reclassification proposal would result in the reclassification of approximately 600 miles of PG&E gas transmission pipelines and associated facilities as distribution mains.

18. PG&E's proposed definition of "distribution center" would allow for lateral pipelines operating above 60 psig but under 20 percent SMYS to be reclassified as distribution rather than transmission pipelines, assuming all other requirements are met.

19. PG&E's proposed new definition of "transmission pipeline," and distribution center" are consistent with the PHMSA Mega Rule Part 2 as reflected in 49 CFR Part 192.3.

20. Applications of PG&E's proposed definitions will result in the reclassification of some 600 miles of transmission pipeline as distribution pipeline, which will lead to lower overall system costs, amongst other reasons because TIMP integrity management procedures are more expensive than the less costly DIMP integrity management procedures.

21. PG&E's actions to reclassify 600 miles of transmission pipeline to distribution bring the gas utilities' interpretations of the definitions of the terms

"transmission pipeline," "large volume customer," and "distribution center" into closer alignment.

22. It is reasonable for PG&E to implement site-specific procedures in conformance with its updated definitions in the 12-18 months following issuance of this decision or a final 2023 general rate case decision, which ever comes last.

23. Authorizing PG&E to further modify its pipeline classifications going forward based on regulatory changes and interpretations is consistent with other operational changes that PG&E may make for safety, compliance and/or process improvement reasons.

24. Approving PG&E's request is important because it will result in lower overall system costs, which will benefit customers.

25. This decision does not address issues related to the Aliso Canyon gas storage facility, which are addressed in I.17-02-002.

26. Natural gas storage facilities are needed for sufficient quantities of natural gas to be available during periods of peak demand to support reliability and affordability.

27. Natural gas storage facilities are necessary to meet winter demand.

28. Natural gas storage facilities play a crucial role in protecting customers from reliability issues and adverse rate impacts in the electricity and gas sectors.

Conclusions of Law

1. If gas transmission infrastructure is needed at its current operating pressure to meet reliability standards, meet state or federal safety requirements, support electric reliability, serve hard-to-electrify customers, or provide for the redundancy needed to allow for routine maintenance, it should be repaired or replaced.

2. Transmission pipelines not needed for the purposes identified in Conclusion of Law 1 should be considered for derating or decommissioning to reduce maintenance costs.

3. Starting January 1, 2024, gas utility applications for approval of transmission infrastructure projects or related revenue recovery should include information that addresses the criteria outlined in Attachment A.

4. Gas utilities should address the information requirements in Attachment A in general rate case applications and in free-standing applications, for projects subject to GO 177 and projects not subject to GO 177.

5. Starting January 1, 2024, the Commission should use the review criteria outlined in Attachment A to inform decision-making regarding gas utility applications for approval of transmission infrastructure projects or related revenue recovery.

6. When considering or implementing transmission pipeline derations, utilities must in all instances comply with PHMSA requirements, including 49 CFR Part 192, Section 193 definitions, and GO 112-F.

7. Before gas assets are derated, replacement energy sources must be built and operational or demand must have declined sufficiently to avoid the system falling below reliability standards or otherwise losing the ability to meet local customers' energy needs.

8. The Commission should require gas utilities to notify the Commission of planned derations in an information-only submittal provided at least 30 days prior to executing a planned transmission pipeline deration.

9. The Commission should require gas utilities to serve the information-only submittals to parties to R.20-01-007 and any successor long-term gas planning proceeding(s).

10. The Commission should require that the information-only submittals provide information about each transmission pipeline to demonstrate that it is no longer needed at full capacity, to demonstrate that the new distribution pipeline is needed to serve customers, and to summarize the anticipated rate impacts of the proposed deration.

11. The Commission should require gas utilities to establish mechanisms to track any changes in transmission pipeline work plans and revenue requirements adopted in a general rate case and, if the utility deviates from these, should require the utilities to notify the Commission and parties to R.20-01-007, and any successor proceeding(s), via an information-only submittal provided no later than 60 days after the work is completed.

12. The regulatory process for derating transmission pipelines adopted in this decision does not preclude gas utilities from reducing the operating pressure of any of their pipelines for safety or operational reasons at their discretion.

13. Later phases of this proceeding may consider the need for an overall strategy for derating or decommissioning of transmission pipelines as well as potential guidance regarding the need for periodic evaluation of transmission pipelines in response to changing demand and reliability standards.

14. The Commission's GO 112-F requirements are in addition to 49 CFR Parts 191-193 and Part 199 and do not supersede PHMSA pipeline safety regulations.

15. Gas utilities must continue to comply with Commission GO 112-F requirements to align with PHMSA definitions as most recently set forth in 49 CFR Part 192.3 or as amended, if relevant, in the future.

16. PG&E's proposal to update its definitions of "distribution center," "transmission [pipe]line," and "large volume customer" resulting in the

reclassification of some 600 miles of transmission pipelines as distribution pipelines is reasonable and should be approved.

17. The Commission should authorize PG&E to maintain pipeline segments that are reclassified from transmission to distribution pipelines in accordance with leak survey requirements for transmission pipelines and to transition the pipelines from TIMP to DIMP integrity management procedures.

18. The Commission should require PG&E to provide specific information on the cost reduction benefits and other impact of its new definitions in a future general rate case or other rate-setting application.

19. The Commission should approve PG&E's proposal to implement site-specific procedures in conformance with its updated definitions in the 12-18 months following issuance of this decision or a final 2023 general rate case decision, which ever comes last.

20. The Commission should authorize PG&E to further modify its pipeline classifications going forward based on regulatory changes and interpretations and to report any such reclassifications in an applicable general rate case or ratesetting application.

21. Natural gas storage facilities are necessary for reliability and cost management.

22. This proceeding should remain open.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company, Southern California Gas Company, and San Diego Gas & Electric Company shall provide information on each criterion set forth in Attachment A when filing an application that requests approval of or

the collection of revenue requirement for any and all new transmission infrastructure projects, starting January 1, 2024.

2. Pacific Gas and Electric Company, Southern California Gas Company, and San Diego Gas & Electric Company shall consider for derating or decommissioning all transmission pipelines that are no longer needed at full capacity to meet reliability standards, meet state or federal safety requirements, ensure electric reliability, serve hard-to-electrify customers, or provide for the redundancy needed to allow for routine maintenance and shall, starting January 1, 2024, notify the Commission of planned derations in an information only submittal provided at least 30 days prior to executing a planned transmission pipeline deration.

3. Pacific Gas and Electric Company, Southern California Gas Company, and San Diego Gas & Electric Company shall adhere to the regulatory review process for transmission pipeline derating contained in Attachment B of this decision, starting January 1, 2024.

4. The Pacific Gas and Electric Company (PG&E) proposal to update its definitions of "transmission pipeline," "distribution center" and "large volume customer" is approved, as is the resulting reclassification of some 600 miles of PG&E transmission pipelines as distribution pipelines. PG&E shall provide specific information on the cost reduction benefits and other impact of its new definitions in a future general rate case or other rate-setting application.

5. The Pacific Gas and Electric Company proposal to transition transmission pipeline segments reclassified as distribution lines as a result of this decision from the Transmission Integrity Management Program to the Distribution Integrity Management Program is approved.

6. The Pacific Gas and Electric Company proposal to implement site-specific procedures in conformance with its updated definitions in the 12-18 months following issuance of this decision or a final 2023 general rate case decision, which ever comes last, is approved.

7. The Pacific Gas and Electric Company (PG&E) proposal to further modify its pipeline classifications going forward based on regulatory changes and interpretations is approved. PG&E shall report any such reclassifications in an applicable general rate case or ratesetting application.

8. Rulemaking 20-01-007 remains open.

This order is effective today.

Dated ____________________, at Sacramento, California.

ATTACHMENT A

Criteria for Repair or Replacement of Aging Transmission Infrastructure Versus Decommissioning or Deration

California Public Utilities Commission

Criteria for Repair or Replacement of Aging Transmission Infrastructure Versus Decommissioning or Deration

1. If the gas transmission infrastructure is needed at its current operating pressure to meet reliability standards,[66] meet state or federal safety requirements, support electric reliability, serve hard-to-electrify customers, or provide for the redundancy needed to allow for routine maintenance, it should be repaired or replaced.[67] An optional consideration may be the need for a transmission pipeline to carry gaseous fuels other than natural gas.

2. The pipeline system as a whole, and replacement or repair projects, must meet safety and reliability standards.

3. If the criteria in #1 are met, consider the Risk-Spend Efficiency or Cost-Benefit Ratios[68] to determine whether repair or replacement is the best option.

(END OF ATTACHMENT A)

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[66] *See* Decision (D.) 22-07-002 and D.06-09-039.

[67] Construction and permitting feasibility may also be considered. Projects with extremely high costs and limited duration of reliability benefits should be given extra scrutiny.

[68] As required in D.18-12-014 and D.22-12-027 and/or any successor decision modifying these.

ATTACHMENT B

Criteria and Regulatory Review Process for Transmission Pipeline Derating

California Public Utilities Commission

Criteria and Regulatory Review Process for Transmission Pipeline Derating

1. Utilities must consider for derating or decommissioning all transmission pipelines that are no longer needed at total nominal capacity to meet design standards or state or federal safety requirements, to ensure electric reliability, to serve hard-to-electrify customers, or to provide for the redundancy needed to allow for routine maintenance.

2. If a transmission pipeline is not needed at its total nominal capacity but cannot deliver sufficient fuel to meet demand at less than 20 percent Specified Minimum Yield Strength it should not be considered for deration.

3. Before gas assets are derated, replacement energy sources must be built and operational or demand must have declined sufficiently to avoid the system falling below reliability standards or otherwise losing the ability to meet local customers' energy needs.

4. Utilities must notify the Commission of planned derations in an information-only submittal[69] provided at least 30 days prior to executing a planned transmission pipeline deration.

5. Utilities must serve the information-only submittals to parties to Rulemaking (R.) 20-01-007 and any subsequent long-term gas planning proceeding.

6. The information-only submittal must:

    a. Provide information about each transmission pipeline to demonstrate that it is no longer needed at total nominal capacity;

    b. Demonstrate that the new distribution pipeline is needed to serve customers;

    c. Summarize the anticipated rate impacts of the proposed deration.

7. The utilities must establish mechanisms to track any changes in transmission pipeline work plans and revenue requirements adopted in a

[69] *See* General Order 96-B at Section 3.9 and Section 6.

general rate case. If the utility deviates from these approved plans and revenue requirement it must notify the Commission and parties to R.20-01-007, and any successor proceeding, via an information-only submittal provided no later than 60 days after the work is completed.

(END OF ATTACHMENT B)