Decision **PROPOSED DECISION OF ALJ BUSHEY (Mailed 1/23/2015)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms.	Rulemaking 11-02-019 (Filed February 24, 2011)

DECISION ADOPTING REVISED GENERAL ORDER 112-F

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DECISION ADOPTING REVISED GENERAL ORDER 112-F

Summary

Today's decision brings forward modern rules for California's natural gas transmission and distribution system operators. General Order 112-F contains new operational and reporting metrics, accelerates leak survey schedules, and, in certain circumstances, adopts California standards that are more stringent than federal requirements.

Since initiating this proceeding in 2011, we have made major changes in the regulation of California's natural gas system operators, including formalizing safety plans and setting aside decades-old pressure test exemptions. Although we see today's decision as another step on our continuing safety journey, we have accomplished the primary goals of this proceeding and set in place permanent oversight mechanisms. Consequently, it is now time for this proceeding to be closed.

1. Background

Pursuant to Pub. Util. Code § 451, 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." Ensuring that the management of investor-owned gas utility systems fully performs its duty of safe operations is a core obligation of this Commission.

We initiated this Rulemaking to consolidate and coordinate our efforts, obtain public input, and propose rule and policy changes as necessary. We set forth the following primary objectives of this proceeding, as well as specific plans for achieving each objective:

A. Provide the public with a means to make their views known to this Commission;

B. Provide the public with the Independent Review Panel's expert recommendations regarding the technical explanation for the explosion, assessment of likelihood that similar events may occur, and recommendations for preventive measures and other improvements;

C. Develop and adopt safety-related changes to the Commission's regulation of natural gas transmission and distribution pipelines, including requirements for construction, especially automated shut-off valves, maintenance, inspections, operation, record retention, ratemaking, and the application of penalties;

D. Consider ways that this Commission can undertake a comprehensive risk assessment for all natural gas pipelines regulated by this Commission, and possibly for other industries that the Commission regulates;

E. Consider available options for the Commission to better align ratemaking policies, practices, and incentives to elevate safety considerations, and maintain utility management focus on the "nuts and bolts" details of prudent utility operations;

F. Consider the appropriate balance between the Commission's obligation to conduct its proceedings in a manner open to the public with the legitimate public safety concerns that arise from unlimited availability of certain utility information;

G. Consider if we need further rules or other protection for whistleblowers to inform the Commission of safety hazards; and

H. Expand our emergency and disaster planning coordination with local officials.

In this proceeding, our primary efforts have been focused on ensuring that California's natural gas transmission system operators are properly determining the Maximum Allowable Operating Pressure (MAOP) for each segment in Decision (D.) 11-06-017 of the natural gas transmission system. Our review caused us, on June 9, 2011, to order all California natural gas transmission pipeline operators to prepare Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plans (Implementation Plans) to either pressure test or replace all segments of natural gas pipelines that were not pressure tested or lacked sufficient details related to performance of any such test.[1] We required that the Implementation Plans provide for testing or replacing all such pipeline as soon as practicable, and that at the completion of the implementation period, all California natural gas transmission pipeline segments would be (1) pressure tested, (2) have traceable, verifiable, and complete records readily available, and (3) where warranted, be capable of accommodating in-line inspection devices.

[1] The Commission's General Order (GO) 112, which became effective on July 1, 1961, mandated pressure test requirements for new transmission pipelines (operating at 20% or more of Specified Minimum Yield Strength (SMYS)) installed in California after the effective date. Similar federal regulations followed in 1970, but exempted pipeline installed prior to that time from the pressure test requirement. Such pipeline is often referred to as "grandfathered" pipeline, because pursuant to 49 CFR 192. 619(c), pressure testing was not mandated.

In ~~Decision (~~D.~~)~~ 12-12-030, the Commission authorized Pacific Gas and Electric Company (PG&E) to increase its annual revenue requirement by just under $300 million for 2012, 2013, and 2014 for Implementation Plan projects. That decision mandated pressure testing of 783 miles of pipeline, replacement of 186 miles of pipeline, installation of 228 automated valves, and upgrades to 199 miles of pipeline to allow for in-line inspection.[2] Interim safety measures were also required, pending completion of these needed safety improvements. PG&E shareholders were assigned the costs of pressure testing pipeline for which pressure test records were missing. We also directed PG&E to continue its record management improvement project; however, due to past deficiencies in document management, the costs of this project and its computer data base were not recovered from ratepayers. Although we approved PG&E's cost forecasts for pressure testing and replacement, PG&E's shareholders were required to bear the risk of cost overruns because PG&E's past management decisions led to the need to undertake this massive project on an expedited schedule.

In Application (A.) 13-10-017, PG&E submitted its update to its Implementation Plan, and in D.14-11-023, the Commission approved a settlement agreement which provided for a reduction in the authorized revenue requirement from $299,214,000 to $223,228,000.

[2] As set forth below, these amounts will be updated in accordance with today's decision .

In D.13-10-024, the Commission required Southwest Gas Corporation to enact its Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan, to replace 7.1 miles of natural gas pipeline in its Victor Valley natural gas transmission system, and add a remote controlled shut~~-~~-off valve to its Harper Lake natural gas transmission system. The Commission determined that the cost of the pipeline replacements should be shared between ratepayers and shareholders, and the costs of the shut-off valve will be included in revenue requirement.

In D.12-04-021, the Commission transferred the reasonableness and ratemaking review of the Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan of San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (~~SoCal Gas~~SoCalGas) from this proceeding to the Triennial Cost Allocation Proceeding, A.11-11-002, and authorized a memorandum account for both companies.

Apart from the comprehensive Implementation Plan, PG&E also brought forward specific requests necessary to prepare for the winter heating season. PG&E requested Commission authorization to lift operating pressure restrictions that had been imposed on certain lines following the San Bruno rupture. To consider such requests, the Commission adopted a public process for PG&E to make its demonstration that line operation could be safely restored to pre-restriction levels. The Commission required that PG&E provide documentation showing that it had gone beyond a rote pressure test of the line in question, and include a responsible engineer's review of the pipeline construction and assessment of the results in a Safety Certification. Specifically, the PG&E officer responsible for gas system engineering was required to provide a verified statement showing the following information:

a) that PG&E has validated the pipeline engineering and construction;

b) that PG&E has reviewed pressure tests results and can confirm that a pressure test was performed on the pipeline in accordance with federal regulations; and,

c) that in the professional judgment of the engineering officer, the system would be safe to operate at the proposed restored pressure levels.[3]

In D.11-10-010, the Commission applied these standards and authorized PG&E restore the MAOP of the suction side of the Topock Compressor Station to 660 pounds per square inch gauge (psig). Similarly, the Commission authorized PG&E to increase the maximum allowable operating pressure on natural gas transmission Line 131-30 and associated shorts to 595 pounds psig (D.12-09-003).

On December 15, 2011, the Commission issued D.11-12-048 which authorized PG&E to operate Line 101, 132A, and 147 at pressure no higher than 365 psig. The Commission opened a review of its 2011 decision to lift the operating pressure restrictions on Line 147, and recertified Line 147 with a MAOP of 330 psig in D.13-12-~~0420.~~042.

On May 11 and 12, 2015, the Commission's Safety and Enforcement Division conducted a workshop on calculating Maximum Allowable Operating Pressure in California for natural gas transmission systems. This workshop addressed issues related to the relationship between Commission D.11-06-017 and federal regulations.

2. Public Utilities Code Sections ~~961~~958, 961, and 963

Pub. Util. Code § 958 codifies many of our directives from D.11-06-017, including the requirement for traceable, verifiable, and complete records.

California legislation also emphasized the need for increased and more effective safety procedures, with Pub. Util. Code §§ 961 and 963 requiring each

[3] D.11-09-006 at 18.

gas corporation to develop a plan for the "safe and reliable operation of its commission-regulated gas pipeline facility that implements the policy of paragraph (3) of subdivision (b) of Section 963, subject to approval, modification, and adequate funding by the commission." As provided in Pub. Util. Code § 961(e), the Commission and each gas corporation must "provide opportunities for meaningful, substantial, and ongoing participation by the gas corporation workforce in the development and implementation of the plan, with the objective of developing an industry-wide culture of safety that will minimize accidents, explosions, fires, and dangerous conditions for the protection of the public and the gas corporation workforce."

In D.12-12-009, we expanded the scope of this Rulemaking to explicitly include issues addressed in Pub. Util. Code §§ 961 and 963, and acknowledged that this Commission and our federal counterparts were and are hard at work on many of these issues. The overall safety plans of California's natural gas system operators flow from numerous Commission processes in addition to federal regulations. To provide a comprehensive articulation of these components, e.g., policies, procedures, standards, guidelines, which together form their respective safety plans, we ordered all California natural gas system operators to file and serve no later than June 29, 2012, a natural gas system operator safety plan that shows how the operator addresses each element of Pub. Util. Code §§ 961 and 963 for its gas transmission and distribution facilities.

In D.12-12-009, we accepted for filing the Safety Plans submitted by SDG&E; ~~SoCal Gas~~SoCalGas; PG&E, Southern California Edison Company (SoCal Edison), (Catalina Petroleum Gas Pipeline Distribution System); Southwest Gas Corporation; Gill Ranch Storage, LLC; Lodi Gas Storage, LLC; Central Valley Gas Storage, LLC; Alpine Natural Gas Operating Company, No. 1, LLC; and West Coast Gas Company. We also ordered each operator to continuously monitor and improve such plan, and file updates as directed.

In that decision, we also added a new section to GO 112-E providing for whistleblower protections.

2.1. Audits

In D.12-04-010, we noted that Section 961(e) sets creating a "culture of safety" as an objective of the Commission's regulation of California natural gas systems operators, and that no rules can take the place of corporate leaders who are committed to safety as their first priority and who establish the priorities and values of a corporation, translate those priorities into a safety management system in its daily operations, and, in a routine and habitual basis, instill in the corporation's workers a commitment to safety through personal example and reward systems.

We determined that to evaluate whether California's natural gas system operators have established a "culture of safety," we should audit the gas corporations' implementation of revenue requirements authorized in their General Rate Cases (GRCs) because this Commission most directly exercises its oversight responsibilities through comprehensive review of investor-owned utilities budgets and operations in GRCs. We concluded that these audits should include, but not be limited to, the authorized and budgeted safety-related capital investments and operation and maintenance expenditures of PG&E, SDG&E, and SoCalGas for their last two authorized GRC cycles.

Since D.12-04-010 was issued, we opened Rulemaking (R.)13-06-011 to consider changes to the energy utilities' Rate Case Plans to ensure the effective use of a risk-based decision-making framework to evaluate the safety and reliability improvements that are proposed in their GRC applications.

The new Rate Case Plan framework was adopted in D.14-12-025 and requires the energy utilities to file various reports with the Commission prior to their GRCs describing how they plan to assess and mitigate their risks. Among these reports is the Risk Spending Accountability Report. As with a financial audit, this report would consist of a project-by-project comparison of authorized vs. actual spending accompanied by the utility's narrative explanation of any significant differences of the two.[4] Commission staff is to review the Risk Spending Accountability Reports and to report on their findings.

2.2. Changes to the Commission's Regulations Applicable to Natural Gas Transmission Operators

In GO 112-E, the Commission adopted the federal rules for the design, construction, quality of materials, locations, testing, operations and maintenance of facilities used in the gathering, transmission and distribution of natural gas and in liquefied natural gas facilities in California. The Commission's rules follow the Federal Pipeline Safety Regulations, as the regulations are updated from time to time.

This GO is the linchpin of the Commission's regulation of natural gas pipelines.

On July 8, 2014, the assigned Administrative Law Judge (ALJ) by ruling distributed the set of Proposed Rule Changes to GO 112-E developed by the Commission's Safety and Enforcement Division (SED). The ruling set dates for parties to file and serve comments and reply comments on the Proposed Rule Changes, with accompanying rationale. Subsequently, the Commission staff also held a workshop on the proposed changes.

[4] D.14-12-025, at 44.

The purpose of today's decision is to consider and adopt a revised GO, which will be known as GO 112-F.

3. Discussion

Pursuant to Pub. Util. Code § 451 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.

The duty to furnish and maintain safe equipment and facilities falls squarely on California public utilities, including our natural gas system operators. The burden of continuously keeping all natural gas system facilities safe also rests with these operators.

SED has brought forward proposed revisions to GO 112, and the parties have reviewed and provided comment on the substantive revisions. Several minor text clarifications were also proposed. Generally, the parties supported the revisions and sought several clarifications. One common theme was establishing a mechanism to recover the costs associated with compliance. SoCal Edison, on behalf of its small island Catalina Gas System, expressed particular concern about the costs of compliance and the duration for needed staff training for small gas systems.

The specific proposals are set forth in the table below. Generally, these proposals clarify existing regulations, extend existing regulations into closely related facilities, or cover gaps in federal regulations. Consequently, the parties to this proceeding did not oppose the majority of these proposals:

Proposed Change to General Order 112	Rationale	Section Number
Remove reference to 49 CFR Part 190, text edits for clarity	Part 190 applies only to federal processes, the correctly listed Parts 191,	101, 102 and 104

	192, 193, and 199 apply to states	
Adds definitions of Operator, Vicinity, Covered Task, Near-Miss Events, and Number of Excavation Tickets	Adds definitions of new terms used in revised General Order	105
Expands the scope of events that must be shown in a Gas Incident Report	Requires reporting of all incidents where pressure exceeds MAOP, or where pipeline loses service or requires shut down due to low pressure	122
Specifies information to be reported on leaks and failures, response times, over/under pressure events, employee evaluation results, Lost and Unaccounted For Gas, public liaison activities, and Gas Safety Plan	Incorporates new metric reporting information to be included in Annual Reports	123
Minor text clarifications		124, 141, 161, 181, 182, 183, 201
Reorder and clarify the contents of Installation Reports, and update cost threshold amounts for inflation	Provide easier to follow regulations and adjust amounts for inflation.	125
Adopt duration limits for unprotected outdoor storage of plastic pipe, 4 years medium density, 10 years high density	Lower of three time limits – manufacturer, operator's plan, or 4/10 years.	142
Increases frequency of leak surveys of transmission system to twice a year, Adds	Doubles frequency of transmission system leak surveys because many miles of transmission	143

detailed specification of leak classification and action criteria, operator qualifications, requires removal of encroachments, and use of Compatible Emergency Response Standard	pipeline has not been pressure tested. Provides guidance on prioritizing leak repair, training facilities, protects pipeline from encroachments, and facilitates emergency communications	
Test requirements for pipelines below 100 psig; clearance between gas pipelines and other substructures of 12 inches when paralleling and 6 inches when crossing	Provides testing pressures for all pipeline, and adopts clearance requirements not specified in federal regulations and conforms to General Rule 128 clearance requirements.	144
Record retention requirements for gas transmission lines	All installation and repair records must be retained so long as the pipeline is in service, all repair records for a minimum of 75 years or until next repair or test is performed, whichever is longer.	New section 145
Expands Liquefied Natural Gas Rules to include mobile equipment	Mobile equipment should also be subject to additional safety requirements	162
Whistleblower Protections	As specified in D.12-12-009	New subpart G

Parties did, however, raise objections to two proposals – expanding the definition of High Consequences Areas in Section 105 and increased transmission line leak survey schedule, found in ~~section~~Section 143.

The essence of most objections, *see* e.g., SoCalGas and SDG&E comments at 2, is that implementing these rule change will require significant modifications to a natural gas system operator's automated scheduling, data collection, and work process systems. Written procedures will need to be developed, and personnel trained. All of this will take time and financial resources.

To allow the operators sufficient time to implement these regulations in an orderly and efficient manner, we will set the mandatory effective date of these regulations as no later than January 1, ~~2016.~~2017. This will also allow time to coordinate additional operator's rate case cycle. Operators must, where feasible, implement these regulations before that date. If an operator encounters identifiable and significant obstacles to implementing a specific section, that operator may seek an extension of time to comply with that section via the process set out in Rule 16.6 of the Commission's Rules of Practice and Procedure or its successor. With this timeline for implementation, the objections raised to the proposals are largely addressed.

Therefore, we find public safety will be enhanced with the revisions and additions to GO proposed by SED to GO 112 as summarized above and as set forth in Attachment A. We conclude that the revised GO 112 should be designated GO 112-F. California natural gas operators shall comply with GO 112-F as soon as feasible but no later than January 1, ~~2016,~~2017, unless good cause can be shown requiring an extension of time to comply with a particular section.

The remaining issue we need to consider is whether the financial audits we ordered in D.12-04-010 for two prior natural gas system operator GRCs should continue to be required for their GRCs. These financial audits were part of our effort to ensure that natural gas system operators imbed safety in their decision-making processes.

To decide this issue we look to the outcome of R.13-11-006. The purpose of that rulemaking was to adopt changes to the energy utilities' Rate Case Plans to ensure that the utilities demonstrate in their GRCs that their proposals reflect a sound risk-based decision-making approach to minimize safety risks. As part of the new Rate Case Plan framework, the energy utilities will file with the Commission Risk Spending Accountability Reports according to the schedule adopted in D.14-12-025. These reports will include an accounting of past utility expenditures on a project-by-project basis and are subject to Commission staff review. Accordingly, the Risk Spending Accountability Reports essentially serve the same function of a financial audit and the financial auditing requirement we ordered in D.12-04-~~10~~010 for natural gas system operators GRCs is unnecessary.

With the adoption of General Order 112-F and the Risk Spending Accountability Reports ordered in D.14-12-025, we find that this proceeding has achieved the objectives set four years ago. Accordingly, this proceeding should be closed.

4. Comments on Proposed Decision

The proposed decision of the ALJ 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 ____________, and reply comments were filed on ____________ by ____________.~~and served on February 12, 2015. PG&E requested clarification as to the effective date of the revised sections, and pointed out that Section 105 appeared to be missing from the list of sections to go into effect "as soon as feasible but no later than January 1, 2016." PG&E also requested a balancing account to capture the increased costs of compliance with the new rules.[5] Socal Gas/SDG&E explained that January 1, 2017, was a more reasonable effective date, and PG&E replied in support of this proposal. SoCalGas/SDG&E also sought a ratemaking mechanism to recover implementation costs, and presented recommendations for minor clarifications in several rules. Southwest Gas argued that the Commission is addressing lost and unaccounted for gas and repairs thereof in R.15-01-008. To avoid any potential conflicts, proposed GO 112 Section 123.2, subsections (a),(b) and (i) should be removed or linked to the outcome of that rulemaking. Southwest Gas also suggested that Section 123.2(d) be made consistent with federal rules and require reporting of instances where the pipeline exceeds 100% of allowed build up. ORA recommended that the Commission clarify and codify its rules regarding use of 49 CFR § 192.619(C) to set MAOP. As set forth above, the Commission's Safety and Enforcement Division held a 2-day workshop on this issue. ORA also opposed doubling the frequency of leak surveys, arguing that these increased inspection requirements have no demonstrated safety benefit. [6] The Utility Workers Union of America proposed increased leak detection and survey requirements, as well as rules and processes for addressing leaks.

On February 17, 2015, the following parties filed reply comments: ORA, PG&E, SoCalGas/SDG&E, and the Coalition of California Utility Employees. PG&E opposed ORA's recommendation for a new phase of this proceeding to further litigate §192.619(c). Southwest Gas supported the January 1, 2017, effective date proposed by the other gas operators, and stated that Southwest Gas will implement sooner if feasible. Southwest Gas opposed as unnecessary the additional leak detection and survey requirements advocated by the Utility Workers Union of America. ORA replied in opposition to the utilities' proposals

[5] PG&E Comments at 3 – 4.
[6] ORA Comments at 5 - 6.

for ratemaking mechanisms to immediately pass along increased compliance costs to ratepayers, and recommended that the utilities coordinate their compliance activities with their respective rate case cycles. The Coalition of California Utility Employees reiterated its proposals, and supported those of the Utility Workers Union of America. The Coalition of California Utility Employees opposed ORA's objections to increasing leak surveys.

The City of San Carlos renewed its request that the Commission exercise its equitable powers and order PG&E to reimburse San Carlos for all costs and fees incurred by the City in connection with this matter.[7] As set forth in Pub. Util. Code § 1802(b), the Legislature expressly denied the Commission the authority to award intervenor compensation to "any state, federal, or local government agency, any publicly owned public utility, or any entity that, in the commission's opinion, was established or formed by a local government entity for the purpose of participating in a commission proceeding." The City of San Carlos has not persuaded us that on the facts presented here that the Commission's "equitable powers" are sufficient to overcome this Legislative directive. Therefore, the motion of the City of San Carlos for reimbursement of its costs is denied.

All comments and reply comments have been thoroughly reviewed and analyzed. Where appropriate, revisions have been made to General Order 112-F and today's decision.

5. Assignment of Proceeding

Michel Peter Florio is the assigned Commissioner and Maribeth A. Bushey is the assigned ALJ in this proceeding.

[7] City of San Carlos Comments at 4.

Findings of Fact

1. The Commission opened this proceeding to consider revisions to rules applicable to California natural gas system operators.

2. The Commission's SED brought forward numerous proposed changes to GO 112-E, issued a staff report delineating the proposed changes, received comments, and held a workshop.

3. The proposed changes are summarized in a table in the body of today's decision and are reflected in Attachment A.

4. A mandatory effective date of January 1, ~~2016~~2017 will allow for the orderly and efficient implementation of the new rules set forth in Attachment A.

5. The Risk Spending Accountability Reports required in D.14-12-025 serve the purpose of the financial audits that were ordered in D.12-04-010 and no financial audits need to be ordered in this proceeding.

Conclusions of Law

1. GO 112-F as set forth in Attachment A today's decision should be adopted effective today; except that as to ~~sections~~Sections 105, 122, 123, 125, 142, 143, 144, 145, and 162, the gas operators shall comply with these sections as soon as feasible but no later than January 1, ~~2016,~~2017, unless compliance is extended for a particular provision pursuant to Rule 16.6 of the Commission's Rules of Practice and Procedure or its successor.

2. R.11-02-019 should be closed.

O R D E R

IT IS ORDERED that:

1. General Order 112-F as set forth in Attachment A to today's decision is adopted effective today; except that as to the revised ~~sections~~Sections 105, 122, 123, 125, 142, 143, 144, 145, and 162, the gas operators shall comply with these

sections as soon as feasible but no later than January 1, ~~2016,~~2017, unless compliance is extended for a particular provision pursuant to Rule 16.6 of the Commission's Rules of Practice and Procedure or its successor.

2. Rulemaking 11-02-019 is closed.

This order is effective today.

Dated ______________________________, at San Francisco, California.

ATTACHMENT A

General Order ~~No.~~Altered 112-F

General Order No. 112-F

State of California Rules Governing Design, Construction, Testing, Operation, and Maintenance of Gas Gathering, Transmission, and Distribution Piping Systems.

California Public Utilities Commission

Month xx, 2015

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GENERAL ORDER NO. 112-F

PUBLIC UTILITIES COMMISSION
of the
STATE OF CALIFORNIA

RULES GOVERNING DESIGN, CONSTRUCTION, TESTING, MAINTENANCE, AND OPERATION OF ~~UTILITY~~ GAS GATHERING, TRANSMISSION, AND DISTRIBUTION PIPING SYSTEMS

CHANGE LIST-FOLLOWING IS THE LIST OF DECISIONS AND RESOLUTIONS WHICH AUTHORIZED CHANGES TO GENERAL ORDER 112 APPLICABLE TO GAS ~~UTILITIES~~OPERATORS:

Decision or Resolution No.	Date Effective	Sections Herein Modified Amended or Added
Decision No. 61269	July 1, 1961	Adopted General Order 112 on December 28, 1960
Decision No. 66399	January 1, 1964	Adopted General Order 112-A on December 3, 1963
Decision No 73223	December 1, 1967	Adopted General Order 112-B on October 24, 1967
Decision No. 78513	April 30, 1971	Adopted General Order 112-C on April 2, 1971
Decision No. 80268	July 18, 1972	Subpart I of Part 192 of Title 49 of CFR and Sections 192.607 And 192.611 (e)
Decision No. 82467 92.717(b),	Feb. 13, 1974	192.12, 192.3, 192.379, 192.55,192.65, 192.201(a), 192.727 and Appendices A and B
Decision No. 85280 192.706,	Dec. 30, 1975	192.59, 192.65, 192.225, 192.229, 192,241, 192.705, 192.707 and Appendices A and B
Decision No. 85375	Jan. 27, 1976	192.229 (c)
Decision No. 86874	Jan. 18, 1977	192.3, 192.5, 192.13, 192.111, 192.145, 192.163, 192.167, 192.179, 192.225, 192.227, 192.243, 192.313, 192.317, 192.319, 192.327, 192.451, 192.465, 192.469, 192.481, 192.615, 192.619, 192.707, 192.713, 192.717, 192.727, 192.753, 192.755 and Appendices A and B
Decision No. 90372	June 5, 1979	Adopted General Order No. 112-D in OII No. 1 on June 5, 1979
Decision No. 90921 192.451,	November 22, 1979	192.13, 192.14, 192.63, 192.121, 192.123, 192.313, 192.452, 192.457, 192.465, 192.467, 192.473, 192.475, 192.477, 192.479, 192.481, 192.485, 192.491, 192.619 and Part II Appendices A and B
Decision No. 93791	December 1, 1981	192.121, 192.179, 192.281, 192.283, 192.285, 192.287, 192.455, 192.465 and Part II Appendix A
Decision No. 83-10-039	October 19, 1983	192.745 and 192.747
Decision No. 84-04-008	April 4, 1984	192.3, 192.227, 192.465, 192.477, 192.481, 192.704, 192.705, 192.706, 192.721, 192.723, 192.731, 192.739, 192.743, 192.745, 192.747 and 192.749

Decision No. 84-05-004	May 2, 1984	192.3, 192.7, 192.59, 192.113, 192.117, 192.123, 192.145, 192.163, 192.197, 192.225, 192.227, 192.229, 192.237, 192.239, 192.241, Part II Appendix A, Part II Appendix B,
and		Table of Contents
Decision No. 84-06-002	June 6, 1984	192.59, and 192.123
Decision No. 84-06-028	June 6, 1984	192.465
Decision No. 85-03-012	March 6, 1985	192.144, 192.283, 192.614, 192.707, 193.1015, II H, Part III Appendix A and Table of Contents
Decision No. 86-06-047	June 25, 1986	192.105, 192.143, 192.243, 192.245 and 192.313
Decision No. 88-11-023	November 9, 1988	192.55, 192.113, 192.223, 192.225, 192.227, 192.237, 192.239, 192.611, 192.719, 192.743, Part II Appendices A and B, Table of Contents and Index

Decision No. 95-08-053	September 11, 1995	Adopted General Order 112-E in Application 93-08-053 on August 11, 1995 and Modified Sections 101, 101.2, 101.3, 101.4, 102.1, 102.2, 103.1, 104.1, 105, 121.1, 122.1, 122.2, 123.1, 124.1, 125.1, 125.2, 126.1, 141.1, 142.1, 143.1, 143.2, 144.1, 161.1, 162.1, 162.2, 162.3, 181.1, 182.1, 182.2, 182.3, 182.4, 182.5, 182.6, 182.7, 182.8, 183.1, 183.2, 183.3, 183.4, 183.5, 201.1, 202.2, Appendix A and Appendix B
Resolution No. SU-41	May 22, 1996	Eliminated existing section 122.2 (c) and renumbered following sections
Resolution No. E-4184	August 21, 2008	Modified reporting requirements in Section 122.2 to provide for reporting via the Worldwide Web; Removed obsolete Appendix C
Decision No. xx-yy-zzz	Month xx, 2015	Adopted General Order 112-F in Rulemaking 11-02-019 on Month xx, 2015 and Modified Sections 101, 101.2, 101.4, 102.1, 103.3, 103.4, 104.1, 104.2,105, 122.1, 122.2, 123.1, 124.1, 125.1, 125.2, 141.1, 142.1, 143,143.1, 143.2, 144.1, 161.1, 162.1, 162.2, 162.3, 181.1, 182.1, 182.7, 183.2, 183.4, 201, 202.2, and Appendix A; Added Sections 123.2, 123.3, 125.3, 125.4, 125.5, 125.6, 125.7, 143.4, 143.5, 143.6, 144.2, 145, 145.1, 162.4; and Added Subpart G with Sections 301 and 302.

PART I
GENERAL PROVISIONS

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SUBPART A - GENERAL

101 PREAMBLE

101.1 This General Order shall be known as the "State of California Rules Governing Design, Construction, Testing, Operation, and Maintenance of Gas Gathering, Transmission, and Distribution Piping Systems." It will be referred to herein as "these rules."

101.2 These rules are incorporated in addition to the Federal Pipeline Safety Regulations, specifically, Title 49 of the Code of Federal Regulations (49 CFR), Parts 191, 192, 193, and 199, which also govern the Design, Construction, Testing, Operation, and Maintenance of Gas Piping Systems in the State of California. These rules do not supersede the Federal Pipeline Safety Regulations, but are supplements to the Federal Regulations. Absent modifications to 49 CFR by this General Order, the requirements and definitions within 49 CFR, Parts 191, 192, 193 and 199 prevail.

101.3 There shall be no deviation from this General Order except after authorization by the Commission. If hardship results from application of any rule herein prescribed because of special circumstances, application may be made to the Commission to waive compliance with such rule in accordance with Section 3(e) of the Natural Gas Pipeline Safety Act of 1968. Each request for such waiver shall be accompanied by a full and complete justification.

101.4 Operators shall maintain the necessary records to establish that they have complied with these rules and the Federal Pipeline Safety Regulations, 49 CFR, that are applicable. Such records shall be available for inspection at all times by the Commission or Commission Staff.

102 PURPOSE

102.1 The purpose of these rules is to establish, in addition to the Federal Pipeline Safety Regulations, minimum requirements for the design, construction, quality of materials, locations, testing, operations and maintenance of facilities used in the gathering, transmission and distribution of gas and in liquefied natural gas facilities to safeguard life or limb, health, property and public welfare and to provide that adequate service will be maintained by gas Operators under the jurisdiction of the Commission.

102.2 These rules are concerned with safety of the general public and employees' safety to the extent they are affected by basic design, quality of the materials and workmanship, and requirements for testing and maintenance of gas gathering, transmission and distribution facilities and liquefied natural gas facilities.

103 INTENT

103.1 The requirements of these rules, in addition to the Federal Pipeline Safety Regulations, are adequate for safety under conditions normally encountered in the gas industry. Requirements for abnormal or unusual conditions are not specifically proscribed. It is intended that all work performed within the scope of these rules shall meet or exceed the safety standards expressed or implied herein.

103.2 Existing industrial safety regulations pertaining to work areas, safety devices, and safe work practices are not intended to be supplanted by these rules.

103.3 Compliance with these rules is not intended to relieve an Operator from any statutory requirements.

103.4 The establishment of these rules shall not impose upon Operators , and they shall not be subject to any civil liability for damages, which liability would not exist at law if these rules had not been adopted.

104 PROCEDURES FOR KEEPING GENERAL ORDER UP-TO-DATE

104.1 It is the intent of the California Public Utilities Commission to automatically incorporate all revisions to the Federal Pipeline Safety Regulations, 49 CFR Parts 191, 192, 193, and 199 with the effective date being the date of the final order as published in the Federal Register.

104.2 In those instances where additional or more stringent specific state rules are appropriate, the gas Operators subject to these rules may file an application to update provisions, rules, standards and specifications of the General Order as they deem necessary to keep this General Order current in keeping with the purpose and intent thereof. However, nothing herein shall preclude other interested parties from initiating appropriate formal proceedings to have the Commission consider any changes they deem appropriate, or the Commission from acting upon its own motion.

105 DEFINITIONS

<u>Commission or CPUC</u> means the Public Utilities Commission of the State of California.

<u>Holders</u> means any structure used to store gas, which either has a displacement of 500 or more cubic feet, or will contain 10,000 or more standard cubic feet of gas at its maximum design pressure, except that a pipeline which is used primarily for transmission or

distribution of gas, but which also serves a storage function, is not a holder for purposes of this General Order.

Inert gas means a gas which will not burn or support combustion, such as nitrogen, carbon dioxide or mixtures of such gases.

Utility means any person, firm, or corporation engaged as a public utility in transporting natural gas, liquefied natural gas (LNG), hydrocarbon gas, or any mixture of such gases for domestic, commercial, industrial, or other purposes.

Operator means any utility, person or entity operating a natural gas transmission or distribution system, including master-meter distribution system subject to PU Code Section 4351-4361, or a propane gas (LPG) distribution system subject to PU Code Section 4451-4465.

Vicinity means an area surrounding an event in which an Operator's gas pipeline facilities could have been a contributing factor to the event

Public Attention means any event that escalates to a level that initiates calls/complaints concerning a common safety concern being submitted to an Operator from 10 or more individuals or organizations. This can include, for example, large scale reports of the smell of gas by customers in the vicinity of an Operator's gas facilities. Public Attention criterion does not necessarily include an individual, or a crowd of persons, watching work being performed on company facilities.

Covered Task means those tasks defined by 49 C.F.R §192.801, but also includes "new construction" in the federal definition of "covered task." Accordingly, the commission defines a covered task that will be subject to the requirements of 49 CFR §§ 192.803 through 192.809 as an activity, identified by the Operator, that:

(a) Is performed on a gas pipeline;

(b) Is an operations, maintenance, or new construction task;

(c) Is performed as a requirement of 49 CFR, Part 192; and

(d) Affects the operation or integrity of the gas pipeline.

High Consequence Area (HCA) is defined by 49 CFR §192.903, which allows two different methods to be used towards determining locations where HCAs exist. However, in an effort to be more conservative towards ensuring the safety in areas of more densely populated areas, the Commission restricts the use of Method 2 in 49 CFR §192.903, in determining HCAs to pipeline segments of 12-inches or less. Accordingly, the Commission modifies paragraph (2) of the High Consequence Area defined by 49 CFR §192.903 to read as follows:

> (2) The area within a potential impact circle of a pipeline 12-inches or less in diameter containing –

HCAs newly identified through the Commission's restriction on Method 2 shall be scheduled for baseline assessment in accordance with 49 CFR §192.905(c) and 49 CFR §192.921(f).

Near-miss events mean unplanned or undesired events that adversely affect an Operator's facilities or operations but do not result in injury, illness, damage, release of gas, loss of gas service, over-pressurization of gas pipeline facilities, or in a reportable incident, but had the potential to do so. Such events include, but are not limited to:

(a) A subsurface pipeline facility not marked or mismarked for excavation purposes;

(b) Excavation activity near a pipeline facility conducted without a valid Underground Service Alert ticket;

(c) The incorrect, or unintentional, operation of a valve or pressure regulator;

(d) An incorrectly mapped pipeline facility;

(e) Work activity in which a standard, procedure, or process approved by an Operator was correctly applied but the activity, nonetheless, resulted in creating a situation or condition where damages or injuries could have easily occurred.

Number of excavation tickets or Number of excavation damages reported per the data requirements of Section 123, **Annual Reports**, means to include all original and renewal notices received by the Operator from the applicable One-Call center.

SUBPART B - REPORTS

121 GENERAL

121.1 In order that the Commission may be informed concerning the operation and the status of the more important facilities of the utilities, the following information shall be filed with the Commission.

122 GAS INCIDENT REPORTS

122.1 Each Operator shall comply with the requirements of 49 CFR Part 191, for the reporting of incidents to the United States Department of Transportation (DOT). The Operator shall submit such reports directly to the DOT, with a copy to the California Public Utilities Commission (CPUC).

122.2 Requirements for reporting to the CPUC.

(a) Each Operator shall report incidents to the CPUC that meet the following criteria:

1. Incidents which require DOT notification.
    - i. An event that involves a release of gas from a pipeline, or of liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:
        - A death, or personal injury necessitating in-patient hospitalization; or
        - Estimated property damage of $50,000 or more, including loss to the Operator and others, or both, but excluding cost of gas lost;
        - Unintentional estimated gas loss of three million cubic feet or more;
    - ii. An event that results in an emergency shutdown of an LNG facility. Activation of an emergency shutdown system for reasons other than an actual emergency does not constitute an incident;
    - iii. An event that is significant in the judgment of the Operator, even though it did not meet the criteria of Sections 122.2(a)(1)(i) or (ii), above.
2. Incidents which have either attracted public attention or have been given significant news media coverage, that are suspected to involve natural gas and/or propane (LPG) gas, which occur in the vicinity of

the Operator's facilities; regardless of whether or not the Operator's facilities are involved.

3. Incidents where the failure of a pressure relieving and limiting stations, or any other unplanned event, results in pipeline system pressure exceeding its established Maximum Allowable Operating Pressure (MAOP) plus the allowable build up set forth in 49 CFR § 192.201.
4. Incidents in which an under-pressure condition, caused by the failure of any pressure controlling device, or any other unplanned event other than excavation related damage, results in any part of the gas pipeline system losing service or being shut-down.

(b) In the event of an incident listed in 122.2(a) above, an Operator shall go to the Commission's website, select the link to the page for reporting emergencies and follow the instructions thereon. If internet access is unavailable, the Operator may report using the backup telephone system.

1. If the Operator is notified of the incident during its normal working hours, the report should be made as soon as practicable but no longer than 2 hours after the utility is aware of the incident and its personnel are on the scene.
2. If the Operator is notified of the incident outside of its normal working hours, the report should be made as soon as practicable but no longer than 4 hours after the utility is aware of the incident and its personnel are on the scene.
3. All reports required by this section shall be followed by the end of the next working day by an email or telefacsimile (fax) of the standard reporting form, "Report of Gas Leak or Interruption," CPUC File No. 420 (see attachment).

(c) Written Incident Reports .

1. The Operator shall submit to the CPUC on DOT Form PHMSA F7100.1 (http://ops.dot.gov/library/forms/forms.htm#7100.1)for distribution systems and on DOT Form PHMSA F7100.2 (http://ops.dot.gov/library/forms/forms.htm#7100.2) for transmission and gathering systems a report describing any incident that required notice under Item 122.2(a)(1).
2. Together with the form required by (c)(1) above, the Operator shall furnish a letter of explanation giving a more detailed account of the incident unless such letter is deemed not necessary by the CPUC staff. The Operator may confirm the necessity of a letter of explanation by email. If, subsequent to the initial report or letter, the Operator discovers additional material, information related to the incident, the Operator shall furnish a supplemental report to the CPUC as soon as practicable, with a clear

reference by date and subject to the original report. These letters, forms, and reports shall be held confidential under the provisions of Paragraph 2, Exclusions, of General Order 66-C and Public Utilities Code Section 315.

3. The Operator of a distribution system serving less than 100,000 customers need not submit the DOT forms required by paragraph (1) above; however, such Operator must submit the letter of explanation required by (2) above, subsequent to any initial report to the CPUC, unless such letter is deemed unnecessary by the CPUC staff.

(d) Quarterly Summary Reports. Each utility shall submit to the CPUC quarterly, not later than the end of the month following the quarter, a summary of all CPUC reportable and non-reportable incidents which occurred in the preceding quarter as follows:

1. Incidents that were reported through the Commission's Emergency Reporting website.
2. Incidents for which either a DOT Form PHMSA F7100.1 or F7100.2 was submitted.
3. Incidents which involved escaping gas from the utility's facilities and property damage including loss of gas in excess of $1,000.
4. Incidents which included property damage between $0 and $1,000, and involved fire, explosion, or excavation related damage.
5. Incidents where the failure of a pressure relieving and limiting stations, or any other unplanned event, results in pipeline system pressure exceeding its established Maximum Allowable Operating Pressure (MAOP) plus the allowable build up set forth in 49 CFR § 192.201.
6. Incidents in which an under-pressure condition, caused by the failure of any pressure controlling device, or any other unplanned event other than excavation related damage, results in any part of the gas pipeline system losing service or being shut-down.

123 ANNUAL REPORTS

123.1 Each Operator shall submit to the DOT, with a copy to the CPUC, annual reports and mechanical fitting failure reports as required by 49 CFR, Part 191, §§191.11, 191.12 and 191.17. Such reports shall be submitted in the manner prescribed in 49 CFR Part 191.

123.2 At the same time copies of the reports required by paragraph 123.1 are submitted, each Operator shall submit, in a format and guidance provided by the Commission's Safety and Enforcement Division or its successor, the following information to demonstrate to the Commission and the public an Operator's efforts towards minimizing the risk from system leaks and failures:

a) Number of gas leaks repaired associated with grades, causes, pipeline materials, sizes, and decades of installation.

b) For leaks repaired in the calendar year, show time between finding the leak and its repair in intervals of 0-3 months; 3-6 months; 6-9 months; 9-12 months; 12-15 months; and greater than 15 months. For the aggregated value of leaks repaired greater than 15 months, segregate the value into leaks that are never regraded; regraded once; regarded twice; regraded three times; and regraded more than three times.

c) Response times in five-minute intervals, segregated first by business hours (0800 – 1700 hours), after business hours and weekends/legal state holidays, and then by Division, District, and/or Region, to reports of leaks or damages reported to the Operator by its own employees or by the public. The intervals start with 0-5 minutes, all the way to 40-45 minutes, an interval of 45-60 minutes and then all response times greater than 60 minutes.

The timing for the response starts when the utility first receives the report and ends when an Operator's qualified representative determines, per the Operator's emergency standards, that the reported leak is not hazardous or the Operator's representative completes actions to mitigate a hazardous leak and render it as being non-hazardous (i.e., by shutting-off gas supply, eliminating subsurface leak migration, repair, etc.) per the Operator's standards . In addition, the Operator must report, using the same intervals, the times for the first company responder to arrive on scene.

d) The number of events in which pressure in any pipeline facility exceeded the maximum allowable operating pressure (MAOP) by 50% or more of the build up allowed for by 49 CFR § 192.201. For any transmission pipeline facility where the Operator applies the provisions of 49 CFR § 192.917 (e)(3) or (e)(4), any increases above the maximum operating pressure must be reported. Also, for low-pressure systems (i.e., inches of water column pressure), all pressure increases above MAOP must be reported. Increases in pressure above MAOP resulting from planned, designed, testing, or other intentional operations performed per procedures or process established by the Operator are exempted from this requirement. For purposes of reporting, "events" includes each occurrence of overpressurization that develops between overpressurization being noted and maintenance being performed.

e) The amount of time it takes for changes, repairs, or new facilities to be finalized and updated, per the Operator's procedures, to the Operator's facilities maps. The provided information shall show the number of facilities mapped segregated into the following time intervals:

1. Less than 14 days;

2. More than 14 days, but less than 30 days;
3. More than 30 days, but less than 90 days;
4. More than 90 days, but less than 180 days;
5. More than 180 days, but less than 360 days;
6. More than 360 days.

f) The number of employees, by operating Division, District, Region, or Other (i.e., an employee of a mobile workforce not assigned to Division, District, or Region) evaluated, and those disqualified after evaluations, performed by the Operator per 49 CFR§ 192.805 (d) or (e).

g) The 32 metrics required to be tracked per 49 CFR § 192.945(a) and ASME B31.8S, Chapter 9, Table 9.

h) Excavation Damage Prevention Related Data

1. Number of excavation damages and related costs involving homeowners;

2. Number of damages and related costs involving agencies (i.e., Caltrans, non-pressurized sewer, etc.) excluded per California Government Code 4216 (GC4216);

3. Number of person-days, along with total costs, devoted to: i) excavation field meetings (per GC4216); and ii) stand-by activities for preventing damage to subsurface facilities during an excavation;

4. Number of person-days, along with total costs, devoted to: i) mark and locate activities (per GC 4216); and ii) all other subsurface damage prevention activities excluding those from paragraph 3 above.

i) Lost and Unaccounted For Gas (LUAF Gas)

1. A listing of the different causes of LUAF Gas that the Operator tracks as part of its operations; and

2. An accounting of the contribution by each of the different causes of LUAF Gas, actual and/or estimated values, which factor into the aggregated LUAF Gas value provided by the Operator on all reports submitted pursuant to subsection 123.1. An Operator must provide details on how each estimated value is derived.

j) Public Liaison Activities

1. The number of public liaison activities scheduled by the Operator and the number of public liaison activities actually performed along with details to explain what caused the difference between the scheduled and performed liaison activities.

2. A summary of public agencies (by county and agency name) to which the Operator provided notice of, and made available for participation, its annual liaison sessions during each of the five calendar years preceding the reporting year. The summary must also denote which agencies were able to have representation at the session.

3. In an effort to provide a convenient resource for the public to use towards confirming that Operators and first responders continue to work together in better coordinating responses to emergencies, each Operator shall make the same information provided per paragraph 2 above available on its website with a link to the same information provided on the CPUC website. Attendance of agencies at liaison sessions is voluntary and may be dependent on agencies having to allocate resources to emergencies that occur when sessions are scheduled.

k) Gas Safety Plan

1. Each Utility Operator must submit a Gas Safety Plan, as codified by Pub. Util. Code §§ 961 and 963, and as ordered by the Commission in D.12-04-010.

2. Each Utility Operator must make any modifications to its Gas Safety Plan identified by the Commission's Safety and Enforcement Division, or its successor.

123.3 All information submitted by an Operator pursuant to paragraph 123.2 shall be submitted with verification, under penalty of perjury, from a senior officer of the utility, at the level of Vice-President or above, stating that the facts contained in the information are true and correct to the best knowledge of that senior officer.

124 REPORTING SAFETY-RELATED CONDITIONS

124.1 The requirements of 49 CFR, Part 191, §§191.1, 191.7, 191.23, and 191.25, to report specified safety-related conditions, are incorporated by references as part of these rules. Copies of all reports submitted to the DOT pursuant to the foregoing requirements shall be submitted to the Commission concurrently.

125 PROPOSED INSTALLATION REPORT

125.1 This section applies to the construction of a new pipeline, or the reconstruction or reconditioning of an existing pipeline. In addition to the requirements of this section, copies of all reports submitted to the DOT pursuant to the requirements of 49 CFR, Part 191, §191.22(c)(1) shall be submitted to the Commission concurrently.

125.2 The proposed installation reports required by this section shall be filed based on the following:

(a) For utilities with less than 50,000 services in the state of California according to the Annual DOT Report, Form PHMSA F 7100.1-1 that is required by 49 CFR §191.11, the Proposed Installation Report shall be submitted to the Commission for any installation that is estimated to cost $1,400,000 or more. The Annual DOT Report referenced above shall be the report filed by the utility for the year previous to that of the proposed installation; or

(b) For utilities with 50,000 services or more in the state of California according to the Annual DOT Report, Form PHMSA F 7100.1-1 required by 49 CFR §191.11, the Proposed Installation Report shall be submitted to the Commission for any installation that is estimated to cost $3,500,000 or more. The Annual DOT Report referenced above shall be the report filed by the utility for the year previous to that of the proposed installation.

125.3 Definitions:

(a) “Construction of a new pipeline” means the installation of pipeline that will serve as a loop or extension to an existing pipeline or as an independent or stand-alone pipeline, any of which will be placed in service for the first time by an utility who filed a Form PHMSA F-7100.1-1 for the calendar year preceding the year in which construction takes place. An utility commencing service for the first time shall file a Proposed Installation Report with the Commission after receiving any necessary Certificate of Public Convenience and Necessity (CPCN) approval from the Commission and prior to the start of construction of the approved project. A CPCN is not required for an extension within a city, county, city and county, or territory within which an utility already lawfully provides service.

(b) "Reconstruction of an existing pipeline" means the installation of pipeline that will replace an existing pipeline or pipeline segment due to alignment interference, deteriorating or aging conditions, pressure/capacity enhancement, or other reason.

(c) "Reconditioning of an existing pipeline" is defined as the work associated with repairing, structurally reinforcing, the replacement of fittings or short segments of pipe, or for the removal and reapplication of pipe coating. The term does not include altering or retrofitting a pipeline or its appurtenances to allow for the passage of internal inspection devices.

125.4 At least 60 days prior to the construction of a new pipeline, reconstruction, or reconditioning of an existing pipeline, a report shall be filed with the Commission setting forth the proposed route and general specifications for such pipeline. The specifications shall include but not be limited to the following items:

(a) Description and purpose of the proposed pipeline.
(b) Specifications covering the pipe selected for installation, route map segregating incorporated areas, class locations and design factors, terrain profile sketches indicating maximum and minimum elevations for each test section of pipeline, and, when applicable, reasons for use of casing or bridging where the minimum cover will be less than specified in §192.327.
(c) Maximum allowable operating pressure for which the line is being constructed.
(d) Test medium and pressure to be used during strength testing.
(e) Protection of pipeline from hazards as indicated in §192.317 and §192.319.
(f) Protection of pipeline from external corrosion.
(g) Estimated cost with supporting detail.

125.5 In cases of reconditioning projects that do not result in relocating pipeline from the general location it occupies prior to the project, the information stated in Section 125.4 (b) does not need to be provided within the report filed per Section 125.4.

125.6 In cases of projects necessary on an emergency basis, the report required by Section 125.4 shall be filed with the Commission as far in advance of the project as practicable, but no later than 5 business days after the project has been initiated. Reports filed for emergency projects, in addition to other information required per Section 125.4, must also detail reasons that necessitated the project being performed on an emergency basis.

125.7 During strength testing of a pipeline to be operated at hoop stresses of 20 percent or more of the specified minimum yield strength of the pipe used, any failure shall be reported on appropriate forms established by the Commission.

126 CHANGE IN MAXIMUM ALLOWABLE OPERATING PRESSURE

126.1 Except as provided in **(126.2)** below, at least 30 days prior to an increase in the maximum allowable operating pressure of a pipeline, a report shall be filed with the Commission for:

a) A pipeline operating at or to be operated at a hoop stress of 20 percent or more of the specified minimum yield strength of the pipe being up rated.

b) 2,500 feet or more of distribution main which is to be up rated from a MAOP less than or equal to 60 psig to a MAOP greater than 60 psig.

c) The conversion of 5,000 feet or more of low pressure distribution main to high pressure distribution main.

The report shall include:

i) the new maximum allowable operating pressure
ii) the reasons for the change
iii) the steps taken to determine the capability of the pipeline to withstand such an increase

126.2 The requirements of **(126.1)** above do not apply to the up rating or conversion of low pressure distribution mains serving less than 300 customers accomplished by connecting the service lines individually to a higher pressure main.

SUBPART C - CONSTRUCTION & SAFETY STANDARDS

141 GENERAL

141.1 Each Operator shall comply with the requirements of 49 CFR Part 192 Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards. This section of the General Order addresses specific construction, testing, and safety standards in addition to those included in 49 CFR Part 192. These rules do not supersede the Federal Pipeline Safety Regulations, but are supplements to them.

142 PLASTIC PIPE

142.1 Plastic Pipe Storage - At the time of installation, plastic pipe to be used for gas transportation, shall not have been subjected to unprotected outdoor exposure longer than the time recommended by the manufacturer, the time period specified in the Operator's operations and maintenance plan, or 4 years for medium density and 10 years for high density polyethylene pipe, whichever is least. The Operator must maintain documentation from the manufacturer to support all frequencies applied by the Operator for unprotected outdoor exposure.

143 DISTRIBUTION AND TRANSMISSION SYSTEMS

143.1 Leakage Surveys and Procedures

(a) A gas leak survey, using leak detecting equipment, must be conducted in business districts and in the vicinity of schools, hospitals and churches, including tests of the atmosphere in gas, electric, telephone, sewer and water system manholes, at cracks in pavement, and sidewalks, and at other locations providing an opportunity for finding gas leaks, at intervals not exceeding 15 months, but at least once each calendar year.

(b) A gas leakage survey of transmission pipelines, using leak detecting equipment must be conducted at least twice each year and at intervals not exceeding 7 ½ months.

143.2 Leak classification and action criteria – Grade – Definition – Priority of leak repair -

(a) A "Grade 1 leak" is a leak that represents an existing or probable hazard to persons or property and requiring prompt action, immediate repair, or continuous action until the conditions are no longer hazardous.

(1) Prompt action in response to a Grade 1 leak may require one or more of the following:

(i) Implementation of the gas pipeline company's emergency plan pursuant 49 CFR § 192.615;

(ii) Evacuating the premises;

(iii) Blocking off an area;

(iv) Rerouting traffic;

(v) Eliminating sources of ignition;

(vi) Venting the area;

(vii) Stopping the flow of gas by closing valves or other means; or

(viii) Notifying police and fire departments.

(2) Examples of Grade 1 leaks requiring prompt action include, but are not limited to:

(i) Any leak, which in the judgment of the Operator personnel at the scene, is regarded as an immediate hazard;

(ii) Escaping gas that has ignited unintentionally;

(iii) Any indication of gas that has migrated into or under a building or tunnel;

(iv) Any reading at the outside wall of a building or where the gas could potentially migrate to the outside wall of a building;

(v) Any reading of eighty percent of the gas' lower explosive limit (LEL) or greater in an enclosed space;

(vi) Any reading of eighty percent of LEL or greater in small substructures not associated with gas facilities where the gas could potentially migrate to the outside wall of a building; or

(vii) Any leak that can be seen, heard, or felt and which is in a location that may endanger the general public or property.

(b) A "Grade 2 leak" is a leak that is recognized as being not hazardous at the time of detection but justifies scheduled repair based on the potential for creating a future hazard.

(1) Except as required by Section 143.2(d), each Operator must repair or clear Grade 2 leaks within fifteen months from the date the leak is reported. If a Grade 2 leak occurs in a segment of pipeline that is under consideration for replacement, an additional six months may be added to the fifteen months maximum time for repair provided above. In determining the repair priority, each Operator must consider the following criteria:

(i) Amount and migration of gas;

(ii) Proximity of gas to buildings and subsurface structures;

(iii) Extent of pavement; and

(iv) Soil type and conditions, such as frost cap, moisture and natural venting.

(2) Each Operator must reevaluate Grade 2 leaks at least once every six months until cleared. The frequency of reevaluation should be determined by the location and magnitude of the leakage condition.

(3) Grade 2 leaks vary greatly in degree of potential hazard. Some Grade 2 leaks, when evaluated by the criteria, will require prompt scheduled repair within the next five working days. Other Grade 2 leaks may require repair within thirty days. The Operator must bring these situations to the attention of the individual responsible for scheduling leakage repair at the end of the working day. Many Grade 2 leaks, because of their location and magnitude, can be scheduled for repair on a normal routine basis with periodic reevaluation as necessary.

(4) When evaluating Grade 2 leaks, each Operator must consider leaks requiring action ahead of ground freezing or other adverse changes in venting conditions, and any leak that could potentially migrate to the outside wall of a building, under frozen or other adverse soil conditions.

(5) Examples of Grade 2 leaks requiring action within six months include, but are not limited to:

(i) Any reading of forty percent LEL or greater under a sidewalk in a wall-to-wall paved area that does not qualify as a Grade 1 leak and where gas could potentially migrate to the outside wall of a building;

(ii) Any reading of one hundred percent LEL or greater under a street in a wall-to-wall paved area that does not qualify as a Grade 1 leak and where gas could potentially migrate to the outside wall of a building;

(iii) Any reading less than eighty percent LEL in small substructures not associated with gas facilities and where gas could potentially migrate creating a probable future hazard;

(iv) Any reading between twenty percent LEL and eighty percent LEL in an enclosed space;

(v) Any reading on a pipeline operating at thirty percent of the specified minimum yield strength or greater in Class 3 or 4 locations that does not qualify as a Grade 1 leak; or

(vi) Any leak that in the judgment of the Operator personnel at the scene is of sufficient magnitude to justify scheduled repair.

(c) A "Grade 3 leak" is a leak that is not hazardous at the time of detection and can reasonably be expected to remain not hazardous.

(1) Each Operator must reevaluate Grade 3 leaks during the next scheduled survey, or within fifteen months of the reporting date, whichever occurs first. Thereafter, the leak must be reevaluated every calendar year, not to exceed 15 months until the leak is repaired, regraded or no longer results in a reading.

(2) Examples of Grade 3 leaks requiring reevaluation at periodic intervals include, but are not limited to:

(i) Any reading of less than eighty percent LEL in small gas associated substructures, such as small meter boxes or gas valve boxes; or

(ii) Any reading under a street in areas without wall-to-wall paving where it is unlikely the gas could migrate to the outside wall of a building.

(d) Any grade of leaks above Grade 3 can only be downgraded once to a Grade 3 leak without a physical repair. After a leak has been downgraded to Grade 3, the leak must be reevaluated every calendar year not to exceed 15 months. If the Grade 3 leak is upgraded at any time to a higher grade, the leak must be reevaluated and repaired per the Operator's procedures for the higher grade to which the leak is upgraded and may not be downgraded again to Grade 3.

(e) All underground leaks on transmission lines classified as Grade 2 or 3, or any subcategories of grades an Operator may establish between Grade 2 or 3, must be repaired by the Operator either upon discovery or within one year after discovery.

143.3 Valve Maintenance - Each valve, the use of which may be necessary for the safe operation of a distribution system, must be inspected, serviced, lubricated (where required) and partially operated at intervals not exceeding 15 months, but at least once each calendar year.

143.4 Operator Qualification - The equipment and facilities used by an Operator for training and qualification of employees must be identical, or very similar in operation to the equipment and facilities which the employee will use, or on which the employee will perform the covered task.

143.5 Encroachments – With the exception of gas pipeline facilities related to installations in gas meter rooms or other specially designed indoor locations where an outdoor meter installation is not possible or practical, a utility transporting LNG, natural gas or other gas shall not construct any part of a LNG, natural gas or other gas pipeline system under a building. In addition, the utility shall not allow a building or other encroachments to be constructed on to its pipeline right-of-way that would hinder maintenance activities on the pipeline or cause a lengthy delay in accessing its pipeline facilities during an emergency. If the utility finds a building or other encroachment built over a pipeline facility after the effective date of this section, then the utility may require the party causing the encroachment to remove the building or other encroachment from over the pipeline facility or to reimburse the utility for its costs associated with relocating the pipeline system.

The utility shall determine, within 90 days after discovering the encroachment, whether the encroachment can be resolved within 180 days. If the utility determines that the encroachment cannot be resolved within 180 days, the utility shall, within 90 days of discovery of the encroachment, submit to the CPUC a written plan to resolve the encroachment within a period longer than 180 days. The CPUC may then extend the 180-day requirement in order to allow the party causing the encroachment and the utility to implement the written plan to resolve the encroachment. If the utility does not submit a written plan, and the encroachment is not resolved within 180 days of discovery, the utility shall isolate and discontinue service to the section of pipeline on which the encroachment exists. The utility must provide written notice of any imminent service discontinuance per this section to the Commission 30 days prior to discontinuing service.

143.6 Compatible Emergency Response Standard – In establishing emergency response procedures, all gas utilities shall use, at a minimum, the Incident Command Systems (ICS) as a framework for responding to and managing emergencies and disasters involving multiple jurisdictions or multiple agency responses. The ICS used by utilities must be compatible with the ICS used by the first responder community within the State of California, and as detailed in California Government Code Section 8607(a), All gas utilities must have the ICS in place to be activated when necessary to the types of emergency events listed and detailed within the written emergency plans gas utilities are required to maintain per 49 CFR Part 192, §192.615.

144 TEST REQUIREMENTS FOR PIPELINES TO OPERATE BELOW 100 p.s.i.g.

144.1 Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated below 100 p.s.i.g. must be leak tested in accordance with 49 CFR §192.509 and the following:

(a) Each main that is to be operated at less than 1 p.s.i.g. must be tested to at least 10 p.s.i.g.

(b) Each main to be operated at or above 1 p.s.i.g. but less than 60 p.s.i.g. must be tested to at least 90 p.s.i.g.

(c) Each main to be operated at or above 60 p.s.i.g. but less than 100 p.s.i.g. must be tested to a minimum of 1.5 times the proposed MAOP

144.2 Service lines and plastic pipelines must be leak tested in accordance with 49 CFR §192.511 or §192.513, respectively. In addition to these requirements:

(a) Each new service line (other than plastic) intended to be operated at a pressure less than 1 p.s.i.g, must be tested to a minimum pressure of 10 p.s.i.g, for a minimum duration of 5 minutes.

(b) Tie-in connections for pipeline used to repair existing service lines must be pressure tested at the operating pressure.

144.3 Clearance between gas pipelines and other subsurface structures:

(a) All natural gas transmission pipelines must be installed in conformance with the requirements of 49 CFR, Part 192, §192.325.

(b) All natural gas distribution pipelines (main and service) must be installed in conformance with the requirements of 49 CFR, Part 192, §192.325 and the following:

(1) Independently Installed: Gas pipelines, when independently installed, shall be separated, where practicable from electrical supply systems, water, oil, communication, or other pipe systems or other foreign substructures, by a clearance of at least 12 inches when paralleling and by at least 6 inches when crossing. New gas pipelines inserted within, and utilizing as conduit, pipeline facilities installed prior to the effective date of this rule are exempt from the paralleling requirements of this paragraph but not the requirements related to crossings.

(2) Concurrently Installed: Gas pipeline, when concurrently installed with electrical supply systems, water, oil, communication, other pipe systems, or other foreign substructures, shall be installed with the separation required by paragraph 1 of this section, except that by mutual agreement between all of the parties involved there may be less separation for duct systems for supply cables of 0 - 750 volts. (For additional information, please consult Commission General Order 128, Rule 31.4.)

(c) In all instances where the required separations cannot be maintained, it is the responsibility of the party last installing facilities to confer with the utility and ensure that the reduced separations do not adversely impact the integrity of the gas pipeline facilities, which includes any cathodic protection that may be applied to the gas pipeline facilities.

145 TRANSMISSION LINES: RECORDKEEPING

145.1 In addition to the other recordkeeping requirements of these rules, each Operator shall maintain the following records for transmission lines for the periods specified:

(a) The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipeline remains in service or there is no longer pipe within the system of the same manufacturer, size and/or vintage as the pipeline on which repairs are made, whichever, is longer.

(b) The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 75 years. However, repairs, or findings of easement encroachments, generated by patrols, surveys, inspections, or tests required by subparts L and M of 49 CFR Part 192 must be retained in accordance with paragraph (c) of this section.

(c) A record of each patrol, survey, inspection, and test required by subparts L and M of this part must be retained for at least 75 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.

SUBPART D - LNG

161 GENERAL

161.1 Each Operator shall comply with the requirements of 49 CFR Part 193 - Liquefied Natural Gas Facilities: Federal Safety Standards. This section of the General Order addresses specific standards for the design, construction, testing, operation, and maintenance of liquefied natural gas facilities in addition to those included in 49 CFR Part 193. These rules do not supersede the Federal Pipeline Safety Regulations, but are supplements to them.

162 LIQUEFIED NATURAL GAS FACILITIES

162.1 Except for a pipeline facility in operation or under construction before January 1, 1973, no Operator may store, treat, or transfer liquefied natural gas in a pipeline facility unless that pipeline facility meets the applicable requirements of this part and of NFPA Standard No. 59A.

162.2 No Operator may store, treat, or transfer liquefied natural gas in a pipeline facility in operation or under construction before January 1, 1973, unless

(a) The facility is operated in accordance with the applicable operating requirements of this part and of NFPA Standard 59A; and

(b) Each modification or repair made to the facility after December 31, 1972, conforms to the applicable requirements of this part and NFPA Standard 59A, insofar as is practicable.

162.3 The Operator, who is planning to build a LNG facility in the state of California, shall notify the Gas Safety and Reliability Branch 90 days prior to commencing construction on that LNG facility. In addition to the requirements of this section, copies of all reports submitted to the DOT pursuant to the requirements of 49 CFR, Part 191, §191.22(c)(1) shall be submitted to the Commission concurrently.

162.4 All Operators must include mobile LNG equipment within the written operations and maintenance plans required by 49 CFR, Part 192, §192.605, to the extent that they own, operate, or utilize mobile LNG equipment. Such Operators must provide written, detailed procedures for the operation and maintenance of their mobile LNG units which conform to the requirements of 49 CFR, Part 193, §193.2019(a). Moreover, these procedures must include a requirement to perform operational tests of mobile LNG equipment, after any modifications are performed to the equipment (including computer equipment and software) that could affect equipment operation, before using modified equipment for actual field use.

SUBPART E - GAS HOLDERS

181 GENERAL

181.1 Each Operator shall comply with the requirements of 49 CFR Part 192 Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards. This section of the General Order addresses specific standards for the design, construction, testing, operation, and maintenance of gas holders in addition to those included in 49 CFR Part 192. These rules do not supersede the Federal Pipeline Safety Regulations, but are supplements to them.

182 PIPE-TYPE AND BOTTLE-TYPE HOLDERS: DESIGN AND CONSTRUCTION

182.1 All holders shall comply with the requirements of 49 CFR §§192.175 and 192.177.

182.2 Electrical equipment and wiring installed at holders must conform to the National Electrical Code, NFPA-70, so far as that Code is applicable.

182.3 Any holder designed and constructed in accordance with the requirements for location class 1 or 2, but not 3, shall be installed at least 75 feet from a flammable building or adjoining property that may have a flammable building constructed thereon in the future, or from the nearest rail or a track on a railroad private right-of-way. Also, no utility shall construct or install a flammable building within fifty feet of a holder. (A flammable building shall be understood to be a building, roof or siding of which consist of wood or other readily combustible material.)

182.4 Each vent line that exhausts gas from a pressure relief valve or blowdown valve must extend to a location where the gas may be discharged without hazard.

182.5 A device which will maintain a continuous pressure record shall be installed at the inlet or outlet of each holder, except that where a group of holders are jointly connected and are all filled from the same gas source and all empty into a common line or system, only one device will be required. A pressure indicating device shall be installed on each container in the holder.

182.6 Each holder facility must have adequate fire-protection facilities.

182.7 Holders shall be provided with overpressure protection systems complying with the requirements of 49 CFR, §192.195.

182.8 When a holder is constructed adjacent to any existing electric transmission line normally carrying voltages in excess of 50,000 volts, the holder shall be located no nearer to the lines than the height of the poles carrying them.

183 PIPE-TYPE AND BOTTLE-TYPE HOLDERS: PLAN FOR INSPECTION AND TESTING

183.1 All leaks of any consequence in gas pipeline, valves and equipment in the vicinity of a holder must be promptly repaired upon discovery, or as soon as practicable. All hazardous leaks must be remedied at once.

183.2 In addition to other inspections required by this Part, after a high pressure holder has been in service for a period of ten years, and at intervals not exceeding ten years thereafter, a complete and thorough internal and external inspection shall be made and reported upon by competent inspectors who are selected by the utility and are agreeable to the Commission. A copy of the report shall be provided to the Commission.

183.3 In lieu of an internal inspection, when it is not practical to enter the holder, a sufficient number of plugs shall be cut from, or holes bored in, the shell at points believed most subject to internal corrosion, to enable examination for corrosion. The interior of at least one container of a holder constructed entirely of pipe and fittings shall be inspected by removing the end closures and entering the container.

183.4 As an alternative to the above requirements to enter the container, or to cut plugs or bore holes in the holder, a nondestructive test procedure such as ultrasonic testing may be used. The test instrument must be calibrated to measure the wall thickness of the steel plates so that the error of indication shall not vary more than plus or minus two thousandths (±0.002) of an inch.

183.5 When such inspections determine that the holders are in a defective and hazardous condition, they shall be taken out of service until repaired and placed in a safe workable condition. All others in the same group shall immediately be inspected and repaired if found defective. If any portion of the shell of a high pressure holder is located underground and exposed to the soil, inspection of its exterior for corrosion and leaks shall be made by suitable representative excavations at the time of the inspection.

SUBPART F - PETROLEUM GAS VESSEL STATIONS

201 GENERAL

Each Operator shall comply with the requirements of 49 CFR Part 192 -Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards. This section of the General Order addresses specific standards for the design, construction, testing, operation, and maintenance of petroleum gas vessel stations in addition to those included in 49 CFR Part 192. These rules do not supersede the Federal Pipeline Safety Regulations, but are supplements to them.

202 PETROLEUM GAS VESSEL STATIONS

202.1 For the purpose of this section, vessel shall refer to any structure with a capacity of two hundred gallons or more used for the storage of petroleum gas, but shall not refer to those vessels used for transporting purposes.

202.2 Each Operator having a vessel station shall establish a plan for the systematic routine inspection and testing of these facilities in accordance with Appendix A -Petroleum Gas Vessel Stations: Operation, Maintenance, and Inspection, and shall provide for:

(a) Effective training of all personnel associated with the maintenance and operation of the facilities.

(b) Specification of appropriate safe work practices and assurance that those practices are followed.

(c) Effective liaison with local fire departments and other emergency response agencies to assure that these agencies are familiar with the operating facilities to the extent necessary to assure that any required response from them in an emergency is effective, and to assure that the Operator of the facilities is adequately informed of the services that those agencies will provide.

SUBPART G – WHISTLEBLOWER PROTECTIONS

301 General

301.1 Each utility shall post in a prominent physical location, as well as an electronic notice on its website where its employees are likely to see it, a notice containing the following information:

Report unsafe conditions to the Public Utilities Commission by calling the whistleblower hotline at 1(800) 649-7570 or by e-mail to safetyhotline@cpuc.ca.gov.

Under sections 451 of the California Public Utilities Code, every public utility shall furnish and maintain such service, instrumentalities, equipment, and facilities, as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees and the public. Further, under section 963(b)(3) of the California Public Utilities Code, it is the policy of this State that California natural gas utilities and the Commission's regulation of natural gas utilities place safety of the public and the natural gas utilities' employees as the top priority consistent with the principle of just and reasonable cost-based rates. In addition, under section 961(e) of the California Public Utilities Code, the Commission and natural gas utilities must provide meaningful and ongoing opportunities for the utilities' workforce to participate in the utilities' development of a plan for the safe and reliable operations of their pipeline facilities and to contribute to developing an industry wide culture of safety. In view of the above, any employee of the natural gas utility or of an independent contractor working under contract with a natural gas utility, who in good faith, believes that unsafe conditions, services or facilities of the utility threaten the health or safety of its patrons, the employees or the public, has a right to report the conditions to the California Public Utilities Commission. The employee can report the conditions by calling the Commission's Whistleblower Hotline at 1(800) 649-7570, either anonymously or by giving the employee's name, or by sending an e-mail with the pertinent facts and/or documentation to safetyhotline@cpuc.ca.gov. This requirement shall be in addition to any right the employee has to contact any other State of Federal agency, if the employee has reasonable cause to believe that the information discloses a violation of a state or federal statute, or a violation or noncompliance with a state or federal rule or regulation.

302 The Utility Has No Right to Retaliate Against an Employee For Notifying the California Public Utilities Commission

302.1 In addition to other statutes, which provide remedies for retaliation against Whistleblowers (e.g., the California Whistleblower Act, California Labor Code § 1102.5), or any other remedy an employee may have in a court, the Commission prohibits California natural gas utilities from retaliating against any employee, who reports, in good faith, unsafe conditions to the Commission. For purposes of this regulation, the Commission retains the option to impose penalties and any other remedies provided under the California Public Utilities Code for any natural gas utility, which the Commission finds violates this regulation.

APPENDIX A

PETROLEUM GAS VESSEL STATIONS: OPERATION, MAINTENANCE AND INSPECTION

I. Operation and Maintenance

1. Before work which might bring about admission of air is performed on any Petroleum Gas vessel, such as removing the vessel from service for internal inspection, internal repairs or dismantling, all inlet and outlet gas connections, except those opening to the atmosphere, shall be physically removed and the vessel shall be purged with inert gases. The closing of inlet and outlet valves or the blanking off of inlet and outlet flanges shall not be considered sufficient precaution against the formation of an explosive mixture while the vessel is out of service.

Before work which might bring about the admittance of air is performed on a petroleum gas vessel, all possible liquid shall be drained there from before purging is begun. A sufficient quantity of steam shall be used to supplement the inert gases used for purging in order to assure the removal of all petroleum gas before the admittance of air. Before workmen are allowed to enter a vessel removed from service and purged with inert gases, the inert gases shall be purged with air, or in lieu thereof, the workmen entering the vessel shall be equipped with self-contained breathing apparatus meeting the requirements of NFPA 19B and maintained in accordance with manufacturer's recommendations.

When the interior of a vessel that has been removed from service and purged of flammable vapors is scraped, brushed, sprayed, painted, or otherwise worked on in a manner that might bring about the formation of an explosive mixture, an adequate and continuous circulation of outside air through the vessel by means of fans or other devices is required.

The circulation of air shall continue until there is no reasonable probability of the formation of an explosive mixture. While engaged in such work, workers must be provided with a safe supply of air to breathe. If conditions warrant, they shall be provided with appropriate respiratory protection.

Upon returning a purged vessel to service, the air shall be purged from the vessel with inert gases before gas or liquid is allowed to reenter the vessel.

All tests to determine the presence of an explosive mixture in connection with the purging of a vessel with inert gases or air, shall be conducted by competent Operators by means of adequate specifications and gas analysis apparatus. When gas detection equipment is used, the Operator shall calibrate and verify it is in good working order.

Except as herein otherwise provided, it is recommended that all operations set forth in this paragraph, including gas analyses, be performed in accordance with the latest procedure recommended by the American Gas Association Publication, "Purging Principles and Practice."

2. Whenever a vessel is painted, all seams on that portion of the vessel being painted,
which are subject to gas pressure, shall be inspected for leaks.

3. Except as herein otherwise provided, all vessels of this type shall be maintained and operated in accordance with the Unfired Pressure Vessel Safety Orders, issued by the Division of Industrial Safety, Department of Industrial Relations of the State of California, and in effect at the time; however, no reconstruction of vessels is required in order to comply with said Unfired Pressure Vessel Safety Orders, if the vessels were acquired prior to April 1, 1940.

4. All valves, fittings, regulators, and pressure relief devices shall be kept in working order and reasonably protected from trespass.

5. The maximum safe operating pressure of the vessel shall be known to the Operator. This pressure can be determined from the inspection reports of the State Division of Industrial Safety or other qualified inspectors.

6. All drips and drain lines shall be kept free of obstruction and in proper working order at all times.

7. In order to provide for liquid expansion with temperature, Petroleum Gas storage vessels shall not be filled to a greater fraction of their volumes than is permitted by said Unfired Pressure Vessel Safety Orders, in effect at the time.

8. At stations where equipment is employed for vaporizing the gas, the vaporizer shall be located outside of buildings, unless those buildings are devoted exclusively to Petroleum Gas and distribution operations, are of approved fireproof construction, and are well ventilated from points near the floor and roof.

Any device supplying the necessary artificial heat for producing the steam, hot water, or other heating medium for the gas vaporizers shall be equipped with a full safety shutoff control.

When such devices are located under a common roof with the gas vaporizers, they shall be located in a separate compartment or room, which shall be separated from compartments or rooms containing liquefied petroleum gas vaporizers, pumps, or central gas mixing devices by a fire wall containing no openings through which free vapors might flow. Vaporizers employing artificial heat shall be provided with a safety relief valve of adequate capacity at or near the outlet of the vaporizer. Direct-fired Petroleum Gas vaporizers and heaters shall only be allowed after special authorization has been granted by the Commission.

II. Inspection Procedures

1. Each utility shall employ a standard set of inspection forms prescribed by the
Commission for recording data obtained at the time inspections are made.

2. The annual inspection reports for all vessels shall contain a general summary of the operating condition of the vessel and indicate any changes, repairs, or improvements that appear advisable.

3. The annual general inspection report of each vessel shall include a description and typical analysis of the gas or gases stored therein during the past year. Analyses shall particularly indicate the content of hydrogen sulfide, carbon dioxide, oxygen, and other corrosive impurities.

4. Whenever the internal inspection of a vessel is contemplated, it shall first be removed from service and entered in accordance 'with the provisions of I. 1.

5. The following minimum inspections shall be made and recorded.

Annual General Inspection:

General inspection of aboveground vessels for condition, indications of corrosion, and need of painting. Check yard for cleanliness and fencing.

The exposed piping, valves, and fittings of buried vessels shall be examined for general condition, undue strain caused by settlement, and need of painting. All exposed connections, manholes and fittings on vessels, as well as mechanical joints in all exposed piping within fifty feet of any vessel, shall be tested for leaks. All leaks and their disposition shall be shown on the report form. Known or suspected leaks on buried vessels, connections, and fittings shall be uncovered and repaired as soon as practicable. Hazardous leaks shall be repaired at once.

Examination shall be made of foundations and supports for all above ground vessels to ascertain if all saddles and piers are fully supporting the vessel. Any settlement which will produce uneven and excessive strain shall be corrected as soon as practicable to minimize risk to the health and safety of the public.

Check accuracy of liquid gauging equipment. Check operation of vaporizer relief devices. Inspect condition and operation of safety shutoff control on vaporization heating equipment.

Inspection of Underground Vessels for External Corrosion:

> Where a storage vessel is underground and exposed to the soil, inspection of its exterior for soil corrosion and leaks shall be made by suitable representative excavations at least once each ten years.

Additional Inspections:

> Except as hereinafter provided, after a Petroleum Gas vessel has been in service for a period of twenty years, and at intervals not exceeding twenty years thereafter, a complete and thorough internal and external inspection shall be made and reported upon by qualified inspectors, who are selected by the utility and are agreeable to the Commission. For groups of two or more vessels, of the same type of materials and design, built at the same time and subjected during the interval to identical service conditions, no less than twenty percent, nor less than one of the vessels in any such group shall receive the internal inspection after each twenty years of service. If the utility uses the above exception, the vessel or vessels inspected shall be regularly rotated in order that eventually all vessels will have been examined.
>
> When the vessel is buried and/or cannot be entered for an internal inspection, a sufficient number of plugs shall be cut from, or holes bored into, the shell at points believed most subject to internal and/or external corrosion, to enable examination for corrosion.
>
> As an alternative to entering the vessel or to cutting plugs or boring holes in the vessel, a nondestructive test procedure such as ultrasonic testing may be used. The test instrument must be calibrated to measure the wall thickness of the steel plates so that the error of indication shall not vary more than plus or minus two thousandths (± 0.002) of an inch.
>
> Any vessels found to be in a defective and hazardous condition shall be taken out of service until repaired and placed in a safe workable condition, and any other vessels in the same group shall immediately be inspected and repaired if found necessary.
>
> In the years that the inspections described above are made, the utility will not be required to make the regular annual general inspection.

APPENDIX B

CALIFORNIA PUBLIC UTILITIES COMMISSION

Report of Gas Leak or Interruption*

CPUC File No. 420

Part I: CPUC CONTACT INFORMATION

Operator: ______ CPUC Contact: Name ______ Recorder ☐ FAX ☐

Contact Person ______ Date ______ Time: (24hr) ______

CPUC Information Request: Written Report ☐ Sketch/Photo ☐ FD Report ☐

Phone: DOT Notified - Yes ☐ No ☐ DOT Report Number:

Part II: INCIDENT DETAILS

Incident Location ***Incident Time*** ***Reported to the Operator***

City/County: ______ Date ______ Date: ______ Time: (24hr) ______

Address/Location: Time: (24hr) Reported by:

Reason(s) for Reporting (check all that apply)

Gas leak associated with: Emergency action required:

Death ☐ Injury ☐ **$$Damage** ☐ **Media Coverage** ☐ **Traffic Rerouted** ☐ **Area Blocked Off** ☐ **Building Evacuated** ☐

Service Interruption ☐ Operator Judgment ☐ Other Emergency actions (describe)

Transmission Line Test Failure ☐ Required Transmission Line Shutdown ☐

Incident Cause **Dig In** ☐ Fire/Explosion ☐ Construction Defect ☐ Material Failure ☐ Corrosion ☐ Vehicle Impact ☐ Suicide ☐

UNKNOWN - MORE INFORMATION TO FOLLOW ☐ Other (describe)

Escaping Gas Involvement (check all that apply) Leak Only ☐ Fire ☐ Explosion ☐ None ☐

Summary (Briefly describe the incident and the probable cause.)

Gas Equipment Affected (check all that apply) ***Specification of Failed Equipment*** ***Injuries and Fatalities***

Main ☐ Regulator ☐ Meter ☐ Valve ☐ Material Steel ☐ Cast Iron ☐ None ☐

Service Line ☐ Controls ☐ Service Riser ☐ Plastic ☐ Copper ☐ Injuries Fatalities

Customer Facility ☐ Transmission Line ☐ Other ☐ ______ Company:

Other (describe) Pipe Size Operating Pressure Other:

MAOP

Dig In Information ***Estimated Damage***

USA notification required: Yes ☐ No ☐ Name of Excavator: ______ Damage to gas facilities:

USA notified: Yes ☐ No ☐ Excavator Contact Person: ______ Other damage involving gas:

Facilities properly marked: Yes ☐ No ☐ Phone: ______ Total:

Recovery from Incident ***Public Agencies on Scene*** ***Customer Outage***

Date Time (24hr)

☞Co Personnel on Scene Media ☐ Police ☐ Customers out of service

Gas flow stopped Fire ☐ Ambulance ☐ Customer-hours outage

Service restored

Part III: CPUC INVESTIGATION

Is further investigation warranted?	Yes ☐	No ☐		Signature of CPUC Engineer		
Date incident investigated:		Field report attached?	Yes ☐	No ☐	CPUC Inspector:	

*The information contained in this report is provided solely for the confidential use of the Commission and its staff and is not open to public inspection (PUC GO 66-C, Public Utilities Code, Sections 315 and 583).

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Rendering set	Standard

Legend:	
Insertion	
~~Deletion~~	
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Style change	
Format change	
~~Moved deletion~~	
Inserted cell	
Deleted cell	
Moved cell	
Split/Merged cell	
Padding cell	

Statistics:	
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Insertions	48
Deletions	26
Moved from	0
Moved to	0
Style change	0
Format changed	0
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