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**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

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| 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) |

## ADMINISTRATIVE LAW JUDGE'S RULING SETTING SCHEDULE FOR FILING COMMENT ON PROPOSED RULE CHANGES TO GENERAL ORDER 112

The Commission's Division of Safety and Enforcement has developed a set of Proposed Rule Changes to General Order 112-E. The Proposed Rule Changes, with accompanying rationale, are set forth in Attachment A to this ruling. Most of the Proposed Rule Changes have been previously presented to the parties; however, two new rules are included in Attachment A. New rule 143.5 addresses encroachments on utility right-of-way, and new rule 143.6 adopts a compatible emergency response standard.

Parties may file and serve comments on these Proposed Rule Changes no later than July 18, 2014, and reply comments no later than July 25, 2014.

**IT IS SO RULED**.

Dated July 8, 2014, at San Francisco, California.

/s/ MARIBETH A. BUSHEY
Maribeth A. Bushey
Administrative Law Judge

# ATTACHMENT A

# PROPOSED RULE CHANGE - 1

***Rationale for PRC-1:*** *Remove the reference with to GO-112-E to 49 CFR, Part 190, per agreements with PHMSA, which applies only to federal processes. This also provides additional clarity and addresses a minor housekeeping issue.*

## Original Version

### 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 190, 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.

**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** The utilities shall maintain the necessary records to ensure compliance 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 utilities operating under the jurisdiction of the commission.

# Strikeout and Underlined Version

## 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 ~~190~~, 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** The utilities shall maintain the necessary records to ~~ensure compliance~~ 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 ~~and utilities operating~~ under the jurisdiction of the C~~c~~ommission.

# Final Version

## 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.

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**101.4** The utilities 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.

# PROPOSED RULE CHANGE - 2

***Rationale for PRC-2:*** *Remove the reference with to GO-112-E to 49 CFR, Part 190, per agreements with PHMSA, which applies only to federal processes.*

## Original Version

**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 190, 191, 192, 193, and 199 with the effective date being the date of the final order as published in the Federal Register.

## Strikeout and Underlined Version

**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 ~~190~~, 191, 192, 193, and 199 with the effective date being the date of the final order as published in the Federal Register.

## Final Version

**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.

## PROPOSED RULE CHANGE - 3

***Rationale for PRC-3:*** *Provide clarification on existing GO-112-E terms and define new terms related to new metrics or more stringent requirements than otherwise required by 49 CFR, Part 192.*

## Original Version

### 105 DEFINITIONS

Commission means the Public Utilities Commission of the State of California.
Holders 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, hydrocarbon gas or any mixture of such gases for domestic, commercial, industrial, or other purposes.

## Strikeout and Underlined Version

### 105 DEFINITIONS

Commission or CPUC means the Public Utilities Commission of the State of California.
Holders 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 incident in which an operator's gas pipeline facilities could have been a contributing factor to the event.
Public Attention means an event that escalates to a level that initiates calls/complaints concerning a common safety concern being submitted to a utility 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 CFR §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 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 C.F.R §192.905(c).
Near-miss events mean unplanned, 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 an otherwise reportable incident but had the potential to do so. Such events can 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 an Underground Service Alert ticket;

(c) The operation of an incorrect 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.

## Final Version

**105 DEFINITIONS**

Commission or CPUC means the Public Utilities Commission of the State of California.

Holders 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 incident 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 of concerning a common safety concern being submitted to a utility 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).

Near-miss events mean unplanned, 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, or over-pressurization of gas pipeline facilities, or in an otherwise a reportable incident, but had the potential to do so. Such events can 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 an Underground Service Alert ticket;
(c) The operation of an incorrect 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.

# PROPOSED RULE CHANGE – 4

***Rationale for PRC-4:*** *Require the reporting of overpressure and underpressure events on all gas pipeline systems.*

## Original Version

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 (LNG) or gas from an LNG facility and
        - A death, or personal injury necessitating in-patient hospitalization; or
        - Estimated property damage, including cost of gas lost, of the operator or others, or both, of $50,000 or more.
    - ii. An event that results in an emergency shutdown of an LNG facility.
2. Incidents which have either attracted public attention or have been given significant news media coverage, that are suspected to involve natural gas, which occur in the vicinity of the operator's facilities; regardless of whether or not the operator's facilities are involved.

(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 utility 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 utility 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 Items 122.2(a)(1) or (2).

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 telephone. If, subsequent to the initial report or letter, the operator discovers significant additional 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 operator 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 gas leak related 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 operator'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 underground dig-ins.

## Strikeout and Underlined Version

122 GAS INCIDENT REPORTS

**122.1** Each O~~o~~perator shall comply with the requirements of 49 CFR Part 191, for the reporting of incidents to the United States Department of Transportation (DOT). The O~~o~~perator shall submit such reports directly to the DOT, with a copy to the Commission ~~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 (LNG) or gas from an LNG facility and~~ 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, including cost of gas lost, of the operator or others, or both, of $50,000 or more.~~ 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 utility 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 utility 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)~~ or (2)~~.
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 e-mail~~telephone~~. If, subsequent to the initial report or letter, the operator discovers ~~significant~~ 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 operator 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 ~~gas leak related~~ 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 operator'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~~underground dig ins~~.
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, result in any part of the gas pipeline system losing service or being shut-down.

## Final Version

### 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 utility 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 utility 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 operator 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 operator'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.

# PROPOSED RULE CHANGE – 5

***Rationale for PRC-5:*** *Incorporate minor updates in federal regulations and implement requirements for the reporting of metrics discussed in the June 27, 2013 Metrics Workshop.*

## Original Version

**123 ANNUAL REPORTS**

**123.1** Each operator shall submit to the DOT, with a copy to the CPUC, annual reports required by sections 191.11 and 191.17 of 49 CFR Part 191. Such reports shall be submitted in the manner prescribed in 49 CFR Part 191.

## Strikeout and Underlined Version

**123 ANNUAL REPORTS AND MECHANICAL FITTING FAILURE REPORTS**

**123.1** Each operator shall submit to the DOT, with a copy to the CPUC, annual reports and mechanical fitting failure reports required by 49 CFR, Part 191, ~~sections~~ §§191.11, 191.12 and 191.17. ~~of 49 CFR Part 191~~ 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 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 stating that the facts contained in the information are true and correct to the best knowledge of that senior officer.

# Final Version

**123 ANNUAL REPORTS AND MECHANICAL FITTING FAILURE REPORTS**

**123.1** Each operator shall submit to the DOT, with a copy to the CPUC, annual reports and mechanical fitting failure reports 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 stating that the facts contained in the information are true and correct to the best knowledge of that senior officer.

## PROPOSED RULE CHANGE – 6

***Rationale for PRC-6:*** *Minor housekeeping issue.*

### Original Version

**124 REPORTING SAFETY RELATED CONDITIONS**

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

### Strikeout and Underlined Version

**124 REPORTING SAFETY RELATED CONDITIONS**

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

### Final Version

**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.

# PROPOSED RULE CHANGE – 7

***Rationale for PRC-7:** Clarify the requirements for proposed installation reports and adjust the cost thresholds for reporting, that were determined many decades ago, for inflation.*

## Original Version

**125 PROPOSED INSTALLATION REPORT**

**125.1** At least 30 days prior to the construction of a new pipeline, or the reconstruction or reconditioning of an existing pipeline, to be operated at hoop stresses of 20 percent or more of the specified minimum yield strength of the pipe used, 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) Fluid and pressure to be used during proof 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.

For utilities with less than 50,000 services in the state of California according to the Annual DOT Report, Form RSPA 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 $1,000,000 or more. The Annual DOT Report referenced above shall be the report for the previous year to the proposed installation.

For utilities with 50,000 services or more in the state of California according to the Annual DOT Report, Form RSPA 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 $2,500,000 or more. The Annual DOT Report referenced above shall be the report for the previous year to the proposed installation.

**125.2** 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 Secretary of Transportation to comply with the requirement of 191.15, Part 191, Title 49 of CFR.

## Strikeout and Underlined Version

### 125 PROPOSED INSTALLATION REPORT

~~**125.1** At least 30 days prior to the construction of a new pipeline, or the reconstruction or reconditioning of an existing pipeline, to be operated at hoop stresses of 20 percent or more of the specified minimum yield strength of the pipe used, 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) Fluid and pressure to be used during proof 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.~~

~~For utilities with less than 50,000 services in the state of California according to the Annual DOT Report, Form RSPA 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 $1,000,000 or more. The Annual DOT Report referenced above shall be the report for the previous year to the proposed installation.~~

~~For utilities with 50,000 services or more in the state of California according to the Annual DOT Report, Form RSPA 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 $2,500,000 or more. The Annual DOT Report referenced above shall be the report for the previous year to the proposed installation.~~

~~**125.2** 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 Secretary of Transportation to comply with the requirement of 191.15, Part 191, Title 49 of CFR.~~

**125.1** This section applies to the construction of a new pipeline, or the reconstruction or reconditioning of an existing pipeline, to be operated at a hoop stress of 20 percent or more of the specified minimum yield strength.

**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 operator who filed a Form PHMSA F-7100.1-1 for the calendar year preceding the year in which construction takes place. An operator commencing service for the first time shall file a Proposed Installation Report with the Commission after receiving Certificate of Public Convenience and Necessity (CPCN) approval from the Commission and prior to the start of construction of the approved project.

(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 30 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.

## Final Version

**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, to be operated at a hoop stress of 20 percent or more of the specified minimum yield strength.
**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 operator who filed a Form PHMSA F-7100.1-1 for the calendar year preceding the year in which construction takes place. An operator commencing service for the first time shall file a Proposed Installation Report with the Commission after receiving Certificate of Public Convenience and Necessity (CPCN) approval from the Commission and prior to the start of construction of the approved project.

(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 30 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.

# PROPOSED RULE CHANGE - 8

***Rationale for PRC-8:*** *Minor housekeeping issues.*

## Original Version

**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.

## Strikeout and Underlined Version

**141 GENERAL**

**141.1** Each O~~o~~perator shall comply with the requirements of 49 CFR P~~p~~art 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.

## Final Version

**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.

# PROPOSED RULE CHANGE – 9

***Rationale for PRC-9:*** *Place limitations on how long plastic pipe can be stored unprotected outdoors.*

## Original Version

**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.

## Strikeout and Underlined Version

**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, <u>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.</u>

## Final Version

**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.

# PROPOSED RULE CHANGE - 10

***Rationale for PRC-10:*** *Provide clarification, specify requirements related to the prioritization and repair of leaks, and to confirm that employees performing covered tasks are qualified using equipment similar to that used in operations.*

## Original Version

**143 DISTRIBUTION SYSTEMS**

**143.1 Leakage Surveys and Procedures -** A gas detector survey 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.

**143.2 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.

## Strikeout and Underlined Version

**143 DISTRIBUTION AND TRANSMISSION SYSTEMS**

**143.1 Leakage Surveys and Procedures –**

(a) A gas leak ~~gas detector~~ survey, using leak detecting ~~or~~ 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 calendar year and at intervals not exceeding 7 1/2 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 Operator’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's 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 15 months until the leak is 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) Grade 1 and 2 leaks 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 within 15 months and repaired within 21 months.

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

**143.~~2~~3Valve 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 such a pipeline under a building. In addition, the utility shall not allow constructed encroachments 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 encroachments built over a pipeline system after the effective date of this section, then the utility may require the party causing the encroachment to remove the building or other encroachments from over the pipeline 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 discontinue service to the pipeline system. 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.

# Final Version

**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 15 months until the leak is 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) Grade 1 and 2 leaks 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 within 15 months and repaired within 21 months.

(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 constructed encroachments 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 encroachments built over a pipeline system 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 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 discontinue service to the pipeline system. 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.

# PROPOSED RULE CHANGE – 11

***Rationale for PRC-11:*** *Provide clarification for test requirements pertaining to all pipelines, provide clearance requirements not specified in federal regulations, and to align clearance requirement in GO-112-E with the clearance requirement contained the Commission's GO-128.*

## Original Version

**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.

## Strikeout and Underlined Version

**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 section of 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.

## Final Version

**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.

## PROPOSED RULE CHANGE - 12

***Rationale for PRC-12:*** *Establish a section within GO 112-E to specify recordkeeping requirements related to transmission lines.*

## New Rule Section 145 TRANSMISSION LINES: RECORDKEEPING

**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.

# PROPOSED RULE CHANGE - 13

***Rationale for PRC-13:*** *Minor housekeeping issues.*

## Original Version

**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.

## Strikeout and Underlined Version

**161 GENERAL**

**161.1** Each <u>O</u>~~o~~perator shall comply with the requirements of 49 CFR <u>P</u>~~p~~art 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.

## Final Version

**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.

# PROPOSED RULE CHANGE - 14

***Rationale for PRC-14:*** *Incorporate new requirements related to Operator's mobile LNG operations.*

## Original Version

**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 Utilities Safety Branch 90 days prior to commencing construction on that LNG facility.

## Strikeout and Underlined Version

**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 ~~Utilities~~ <u>Gas</u> Safety <u>and Reliability</u> Branch 90 days prior to commencing construction on that LNG facility.

<u>**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</u>

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.

## Final Version

**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.

**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.

# PROPOSED RULE CHANGE - 15

***Rationale for PRC-15:*** *Minor housekeeping issues.*

## Original Version

**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.

## Strikeout and Underlined Version

**181 GENERAL**

**181.1** Each O~~o~~perator shall comply with the requirements of 49 CFR P~~p~~art 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.

## Final Version

**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.

## PROPOSED RULE CHANGE - 16

***Rationale for PRC-16:*** *Minor housekeeping issues.*

## Original Version

**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 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.

## Strikeout and Underlined Version

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

**182.1** All holders shall comply with the requirements of 49 CFR <u>§§</u>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.

## Final Version

### 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.

# PROPOSED RULE CHANGE - 17

***Rationale for PRC-17:*** *Minor housekeeping issues.*

## Original Version

**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 (t 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.

## Strikeout and Underlined Version

**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 C~~c~~ommission.

**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.

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**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.

## Final Version

### 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.

## PROPOSED RULE CHANGE – 18

***Rationale for PRC-18:*** *Minor housekeeping issues.*

## Original Version

**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.

## Strikeout and Underlined Version

**201 GENERAL**

Each operator shall comply with the requirements of 49 CFR P~~p~~art 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.

## Final Version

**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.

# PROPOSED RULE CHANGE – 19

***Rationale for PRC-19:*** *Implement a new subpart within GO 112-E to include whistleblower protections already established as a regulation by D.12-12-009.*

## New Rule – Subpart G –Whistleblower Protections

### SUBPART G – WHISTLEBLOWER PROTECTIONS

**301 General**

**301.1** Each Operator 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.