Guidance to

Operators of Jurisdictional LPG Pipeline Systems

For

Standard Records and Field Inspections

Issued by:

Vermont Department of Public Service

Issued December 31, 2019

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Revision History

Revision Date	Description of Revision
September 23, 2019	Initial draft sent to VFDA for review and comment by October 31, 2019
December 31, 2019	Initial version issued

Introduction

This document has been prepared by the Vermont Department of Public Service (Department), at the request of the Vermont propane operators, to provide clear guidance for what the Department is looking for when performing Standard Records and Field inspections. When performing these inspections, the Department uses, as a basis, the inspection forms prepared by the U.S. DOT Pipeline and Hazardous Safety Administration (PHMSA). The PHMSA inspection forms, which were developed primarily for natural gas, have been modified by the Department to delete the questions not applicable to jurisdictional propane systems[1] and to add references, where appropriate, to NFPA 58 *Liquefied Petroleum Gas Code* and NFPA 59 *Utility LP-Gas Plant Code*, as applicable.[2]

This document contains a section pertaining to Records Inspections, a section pertaining to Field Inspections, and various appendices that may be helpful. In the Records section, the numbered questions are the verbatim questions (although different question numbers) from the PHMSA inspection form that is the basis for the Department's Records inspections. The format of each question in the Records section is as follows:

1. The question text from the PHMSA inspection form is in bold.

> Beneath the numbered question, and indented, is the code section(s) (either 49 CFR Part 192 or NFPA 58) applying to the particular question.

Finally, beneath the code section, is the Department's commentary explaining what record(s) the operator will be required to produce to satisfy the question.

The Field Inspections section of this document follows a different format than the Records section due to the variability of the systems in the field. In the Field Inspections section, a few commonly-found issues are highlighted, and the field inspection form used by the Department is included at the end of this document in Appendix E. If the propane operators wish for the Department to elaborate on any additional questions on the field inspection form, they should provide this feedback to the Department, and this document will be updated to include the requested information.

This document is intended to be an "evergreen" document, the revision of which will strike a balance between being revised as needed to keep current but not being revised so often as to be a moving target. The Department's plan is to review this document and revise, if needed, in December of each year in order to provide each version of the document on approximately a calendar-year basis. Off-cycle changes will be made as PHMSA changes its regulations, issues new interpretations, and if any errors are detected. The revision history will include a detailed description of that content that was revised. Except for changes to PHMSA regulations or new PHMSA interpretations, if the Department is proposing to enforce anything in a more stringent manner, a six-month grace period will be provided to the operators.

[1] See Appendix A for assistance in determining whether a propane system is subject to the jurisdiction of federal minimum pipeline safety standards.

[2] See Appendix B for assistance in determining the applicability of NFPA 58 and NFPA 59.

A draft of this document was issued on September 23, 2019, to the Vermont Fuel Dealers Association (VFDA) for review and comment by October 31, 2019. On October 29, 2019, the VFDA provided comments, which are included in Appendix C. The Department has made every effort to address each of the comments.

A table summarizing the requirements for the 25 questions pertaining to records inspections on the following pages is included in Appendix D. Links to additional reference materials that may be helpful are:

The PHMSA inspection forms can be found at: https://www.phmsa.dot.gov/forms/pipeline-forms
Note: the Records and Field inspection questions included in this guidance document are a subset of the questions found in the "PHMSA Gas Distribution IA Question Set" as not all of the questions are applicable to records and field inspections of LPG systems.

The full text of 49 CFR Part 192 can be found at the US Government Publishing Office web site.
http://www.ecfr.gov/cgi-bin/text-idx?SID=18212e3be46ab4cdf8f3ef2c1adcae4d&mc=true&node=pt49.3.192&rgn=div5

The full text of Public Utility Commission Rule 6.100 (Enforcement of Safety Regulations Pertaining to Intrastate Gas Pipeline and Transportation Facilities) can be found here:
http://puc.vermont.gov/document/board-rule-6100-gas-pipeline-safety

PHMSA's *Guidance Manual for Operators of LP Gas Systems*
https://www.phmsa.dot.gov/training/pipeline/small-lp-gas-operator-guide-april-2017

Records Inspections

An Introductory Note About Records

The federal code (49 CFR Part 192) requirements for maintaining records differ by Subpart of the code and are included in the beginning of each subsection of the Records Inspections section of this document. NFPA 58 and NFPA 59 contain more general requirements for maintaining records, as specified below.

With respect to records, NFPA 58 states the following:

> 14.3.2 Maintenance Manuals.
> 14.3.2.1 Maintenance manuals for all equipment at the facility shall be kept at the facility and shall be available to maintenance personnel. Manuals for normally unattended facilities shall be permitted to be stored at a location where they will be accessible for maintenance personnel servicing the unattended location.
> 14.3.2.2 Maintenance manuals shall include routine inspections and preventative maintenance procedures and schedules.
> 14.3.2.3 Each facility shall maintain a record of all maintenance of fixed equipment used to store and transfer LP-Gas. Maintenance records for normally unattended facilities shall be maintained at the unattended facility or at another location.
> 14.3.2.4 Maintenance records shall be made available to the authority having jurisdiction during normal office hours.
> 14.3.2.5 Maintenance records shall be retained for the life of the equipment.

With respect to records, NFPA 59 states the following:

> 11.3 Operating Records.
> 11.3.1 Each facility shall maintain a record of all operating log sheets and recorded data. These records shall be made available to the authority having jurisdiction upon request during normal office hours.
> 11.3.2 Operating log sheets required under 11.3.1 shall be retained for at least 5 years.
>
> 12.5 Maintenance Records.
> 12.5.1 Each facility shall maintain a record of all maintenance log sheets of process equipment.
> (A) The records shall be made available to the authority having jurisdiction upon reasonable request.
> (B) Maintenance records for normally unattended facilities shall be permitted to be stored at the unattended facility or at another location.
> 12.5.2 Records that are required under 12.5.1 shall be retained for the life of the equipment, while in use, and for 3 years thereafter.

In general, operators of jurisdictional propane systems should maintain records sufficient to demonstrate that the required activities were performed in accordance with the applicable code sections. [The Department previously requested suggestions from the propane operators regarding how to handle the situation where a jurisdictional system is sold/transferred to another operator, but the records are not transferred, and no responses were received on this topic. This issue will be addressed in a subsequent version of this guidance.]

Corrosion Control

Records for corrosion control must be made and retained as follows:

> §192.491 Corrosion control records.
> (c) Each operator shall maintain a record of each test, survey, or inspection required by this subpart [Subpart I—Requirements for Corrosion Control] in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least 5 years, except that records related to §§192.465 (a) and (e) and 192.475(b) must be retained for as long as the pipeline remains in service.

1. Do records indicate the location of all items listed in 192.491(a)?

> §192.491 Corrosion control records.
> (a) Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system. Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.
> (b) Each record or map required by paragraph (a) of this section must be retained for as long as the pipeline remains in service.

The Department will be looking for records or maps indicating the location of the applicable items listed above for each jurisdictional system.

2. Do records adequately document that exposed buried piping was examined for corrosion?

> §192.459 External corrosion control: Examination of buried pipeline when exposed.
> Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion must be examined for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If external corrosion requiring remedial action under §§192.483 through 192.489 is found, the operator shall investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

This question is not applicable for buried plastic pipelines. If the operator did expose a buried metallic (steel or copper) pipeline, the Department will be looking for a record adequately documenting that exposed buried piping was examined for corrosion in accordance with §192.459.

3. Do records adequately document cathodic protection monitoring tests have occurred as required?

> §192.465 External corrosion control: Monitoring.

(a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of 100 feet (30 meters), or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period.

For each jurisdictional system, the Department will be looking for a record for each calendar year (intervals not exceeding 15 months) for each tank or pipeline under cathodic protection indicating that the required monitoring was performed.

4. Do records document details of electrical checks of sources of rectifiers or other impressed current sources?

§192.465 External corrosion control: Monitoring.
(b) Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2 1⁄2 months, to ensure that it is operating.

Do any of the jurisdictional systems being inspected have a rectifier or other impressed current power source? If not, this question is not applicable. If so, the Department will be looking for records indicating the rectifier or other impressed current power source was inspected six times each calendar year, but with intervals not exceeding 2 1⁄2 months.

5. Do records document details of electrical checks interference bonds, diodes, and reverse current switches?

§192.465 External corrosion control: Monitoring.
(c) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance six times each calendar year, but with intervals not exceeding 2 1⁄2 months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.

Do any of the jurisdictional systems being inspected have a reverse current switch, diode, or interference bond whose failure would jeopardize structure protection? If not, this question is not applicable. If so, the Department will be looking for records indicating that the electrical checks specified in 192.465(c) were performed at the required frequency.

6. Do records adequately document actions taken to correct any identified deficiencies in corrosion control?

§192.465 External corrosion control: Monitoring.

(d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.

For any corrosion control deficiencies noted in the monitoring records (question #3), the Department will be looking for a record that prompt remedial action was performed to correct the deficiencies. Many operators' procedures state that these deficiencies will be remediated by the next monitoring cycle, and this is the maximum time interval the Department will accept.

7. Do records adequately document the re-evaluation of buried pipelines with no cathodic protection for areas of active corrosion?

§192.465 External corrosion control: Monitoring.
(e) After the initial evaluation required by §§192.455(b) and (c) and 192.457(b), each operator must, not less than every 3 years at intervals not exceeding 39 months, reevaluate its unprotected pipelines and cathodically protect them in accordance with this subpart in areas in which active corrosion is found. The operator must determine the areas of active corrosion by electrical survey. However, on distribution lines and where an electrical survey is impractical on transmission lines, areas of active corrosion may be determined by other means that include review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

§192.455 External corrosion control: Buried or submerged pipelines installed after July 31, 1971.
(a) Except as provided in paragraphs (b), (c), (f), and (g) of this section, each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following:
(1) It must have an external protective coating meeting the requirements of §192.461.
(2) It must have a cathodic protection system designed to protect the pipeline in accordance with this subpart, installed and placed in operation within 1 year after completion of construction.
(b) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience in the area of application, including, as a minimum, soil resistivity measurements and tests for corrosion accelerating bacteria, that a corrosive environment does not exist. However, within 6 months after an installation made pursuant to the preceding sentence, the operator shall conduct tests, including pipe-to-soil potential measurements with respect to either a continuous reference electrode or an electrode using close spacing, not to exceed 20 feet (6 meters), and soil resistivity measurements at potential profile peak locations, to adequately evaluate the potential profile along the entire pipeline. If the tests made indicate that a corrosive condition exists, the pipeline must be cathodically protected in accordance with paragraph (a)(2) of this section.
(c) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience that—
(1) For a copper pipeline, a corrosive environment does not exist; or
(2) For a temporary pipeline with an operating period of service not to exceed 5 years beyond installation, corrosion during the 5-year period of service of the pipeline will not be detrimental to public safety.

For the jurisdictional systems being inspected, has the operator found any areas of active corrosion on its buried metallic piping with no cathodic protection? If not, then this question is not applicable. If yes, then the operator should provide records demonstrating that these pipelines have been cathodically protected. For buried copper pipelines with no cathodic protection, the operator should produce a record demonstrating by tests, investigation, or experience that a corrosive environment does not exist.

8. Do records adequately document electrical isolation of each buried or submerged pipeline from other metallic structures unless they electrically interconnect and cathodically protect the pipeline and the other structures as a single unit?

> §192.467 External corrosion control: Electrical isolation.
> (a) Each buried or submerged pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.
> (b) One or more insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.
> (c) Except for unprotected copper inserted in ferrous pipe, each pipeline must be electrically isolated from metallic casings that are a part of the underground system. However, if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing.
> (d) Inspection and electrical tests must be made to assure that electrical isolation is adequate.
> (e) An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

Are there other metallic structures in proximity to buried tanks or metallic pipelines such that electrical isolation is required to maintain proper cathodic protection? If not, then this question is not applicable. If yes, then the operator should provide a record to document that electrical isolation has occurred.

9. Do records document that pipelines with cathodic protection have electrical test leads installed in accordance with requirements of Subpart I?

> §192.469 External corrosion control: Test stations.
> Each pipeline under cathodic protection required by this subpart must have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection.
>
> §192.471 External corrosion control: Test leads.
> (a) Each test lead wire must be connected to the pipeline so as to remain mechanically secure and electrically conductive.
> (b) Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe.
> (c) Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

Do the jurisdictional systems being inspected have pipelines under cathodic protection? If yes, then the operator should provide records documenting that pipelines with cathodic protection have electrical test leads installed in accordance with requirements of §§ 192.469 and 192.471. If not, then this question is not applicable.

10. Do records document that the operator has minimized the detrimental effects of stray currents when found?

§192.473 External corrosion control: Interference currents.
(a) Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of such currents.

Is the operator aware of any interference currents that might have a detrimental effect on its corrosion control? If not, then this question is not applicable. If yes, then the operator should provide records to document that the operator has minimized the detrimental effects of those stray currents.

11. Do records document inspection of aboveground pipe for atmospheric corrosion?

§192.481 Atmospheric corrosion control: Monitoring.
(a) Each operator must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

If the pipeline is located:	**Then the frequency of inspection is:**
Onshore	At least once every 3 calendar years, but with intervals not exceeding 39 months
Offshore	At least once each calendar year, but with intervals not exceeding 15 months

(b) During inspections the operator must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.
(c) If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by §192.479.

§192.479 Atmospheric corrosion control: General.
(a) Each operator must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under paragraph (c) of this section.
(b) Coating material must be suitable for the prevention of atmospheric corrosion.
(c) Except portions of pipelines in offshore splash zones or soil-to-air interfaces, the operator need not protect from atmospheric corrosion any pipeline for which the operator demonstrates by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will—
(1) Only be a light surface oxide; or
(2) Not affect the safe operation of the pipeline before the next scheduled inspection.

The Department will be looking for records indicating that each pipeline or portion of pipeline that is exposed to the atmosphere is inspected for evidence of atmospheric corrosion at least once every 3 calendar years, but with intervals not exceeding 39 months. For areas where atmospheric corrosion is found, the Department will be looking for records indicating the operator provided protection against the corrosion as required by §192.479.

Note: per §192.3:

> *Service line* means a distribution line that transports gas from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer's piping, whichever is further downstream, or at the connection to customer piping if there is no meter.

On a related note, the Department recommends that the Company include in its twice-annual Public Awareness messages a reminder of the specific location where the customer assumes responsibility to maintain the "customer's piping."

12. Do records document that each buried or submerged pipeline installed after July 31, 1971, has been protected against external corrosion with an adequate coating unless exempted under 192.455(b)?

> §192.461 External corrosion control: Protective coating.
> (a) Each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must—
> (1) Be applied on a properly prepared surface;
> (2) Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture;
> (3) Be sufficiently ductile to resist cracking;
> (4) Have sufficient strength to resist damage due to handling and soil stress; and
> (5) Have properties compatible with any supplemental cathodic protection.
> (b) Each external protective coating which is an electrically insulating type must also have low moisture absorption and high electrical resistance.
>
> §192.483 Remedial measures: General.
> (a) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of §192.461.

Do the jurisdictional systems being inspected have any buried metallic piping? If not, then this question is not applicable. If yes, then the Department will be looking for records documenting that each buried pipeline has been protected against external corrosion with an adequate coating unless exempted under 192.455(b) (see question #7).

13. Do records document the repair or replacement of pipe that has been corroded to an extent that there is not sufficient remaining strength in the pipe wall?

§192.487 Remedial measures: Distribution lines other than cast iron or ductile iron lines.
(a) General corrosion. Except for cast iron or ductile iron pipe, each segment of generally corroded distribution line pipe with a remaining wall thickness less than that required for the MAOP of the pipeline, or a remaining wall thickness less than 30 percent of the nominal wall thickness, must be replaced. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.
(b) Localized corrosion pitting. Except for cast iron or ductile iron pipe, each segment of distribution line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired.

Has the operator repaired or replaced any pipe that has been corroded to an extent that there is not sufficient remaining strength in the pipe wall? If not, then this question is not applicable. If yes, then the Department will be looking for a record (such as a completed work order) indicating the repair or replacement.

Pressure Testing and MAOP Determination

As an initial matter, the Department emphasizes that it is a violation of federal regulations to operate a jurisdictional pipeline that has not been initially pressure tested and maximum allowable operating pressure (MAOP) determined as follows:

> §192.503 General requirements.
> (a) No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until—
> (1) It has been tested in accordance with this subpart [Subpart J—Test Requirements; §§192.501 through 192.517] and §192.619 to substantiate the maximum allowable operating pressure; and
> (2) Each potentially hazardous leak has been located and eliminated.

Records of pressure testing must be made and retained as follows:

> §192.517 Records.
> (a) Each operator shall make, and retain for the useful life of the pipeline, a record of each test performed under §§192.505 and 192.507. The record must contain at least the following information:
> (1) The operator's name, the name of the operator's employee responsible for making the test, and the name of any test company used.
> (2) Test medium used.
> (3) Test pressure.
> (4) Test duration.
> (5) Pressure recording charts, or other record of pressure readings.
> (6) Elevation variations, whenever significant for the particular test.
> (7) Leaks and failures noted and their disposition.
> (b) Each operator must maintain a record of each test required by §§192.509, 192.511, and 192.513 for at least 5 years.

For MAOP Determination, records must be retained as follows:

> §192.603 General provisions.
> (b) Each operator shall keep records necessary to administer the procedures established under §192.605 [Procedural manual for operations, maintenance, and emergencies].

14. Do records indicate that pressure testing is conducted in accordance with 192.507?

> §192.507 Test requirements for pipelines to operate at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage.
> Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage must be tested in accordance with the following:
> (a) The pipeline operator must use a test procedure that will ensure discovery of all potentially hazardous leaks in the segment being tested.

(b) If, during the test, the segment is to be stressed to 20 percent or more of SMYS and natural gas, inert gas, or air is the test medium—
(1) A leak test must be made at a pressure between 100 p.s.i. (689 kPa) gage and the pressure required to produce a hoop stress of 20 percent of SMYS; or
(2) The line must be walked to check for leaks while the hoop stress is held at approximately 20 percent of SMYS.
(c) The pressure must be maintained at or above the test pressure for at least 1 hour.

This code section typically applies to the tank segment (between the tank and the first-stage regulator) when constructed of steel pipe. For a single-tank system, the Department will accept proof of manufacturer testing of suitable piping (sometimes referred to as a pigtail or hogtail). If this code section is appliable, the Department will be looking for a record that the pressure test was performed in accordance with §192.507.

15. Do records indicate that pressure testing is conducted in accordance with 192.509?

§192.509 Test requirements for pipelines to operate below 100 p.s.i. (689 kPa) gage.
Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated below 100 p.s.i. (689 kPa) gage must be leak tested in accordance with the following:
(a) The test procedure used must ensure discovery of all potentially hazardous leaks in the segment being tested.
(b) Each main that is to be operated at less than 1 p.s.i. (6.9 kPa) gage must be tested to at least 10 p.s.i. (69 kPa) gage and each main to be operated at or above 1 p.s.i. (6.9 kPa) gage must be tested to at least 90 p.s.i. (621 kPa) gage.

This code section would apply to a metallic distribution main for a larger propane system, and would usually not apply to a smaller system. If this question is applicable, the Department will be looking for a record that the applicable piping was pressure tested in accordance with §192.509.

16. Do records indicate that pressure testing is conducted in accordance with 192.511?

§192.511 Test requirements for service lines.
(a) Each segment of a service line (other than plastic) must be leak tested in accordance with this section before being placed in service. If feasible, the service line connection to the main must be included in the test; if not feasible, it must be given a leakage test at the operating pressure when placed in service.
(b) Each segment of a service line (other than plastic) intended to be operated at a pressure of at least 1 p.s.i. (6.9 kPa) gage but not more than 40 p.s.i. (276 kPa) gage must be given a leak test at a pressure of not less than 50 p.s.i. (345 kPa) gage.
(c) Each segment of a service line (other than plastic) intended to be operated at pressures of more than 40 p.s.i. (276 kPa) gage must be tested to at least 90 p.s.i. (621 kPa) gage, except that each segment of a steel service line stressed to 20 percent or more of SMYS must be tested in accordance with §192.507 of this subpart.

This code section would apply to metallic first-stage piping (to be operated at approximately 10 psig between the first-stage and second-stage regulators). If this question is applicable, the Department will be looking for a record that the applicable piping was pressure tested in accordance with §192.509.

17. Do records indicate that pressure testing is conducted in accordance with 192.513?

> §192.513 Test requirements for plastic pipelines.
> (a) Each segment of a plastic pipeline must be tested in accordance with this section.
> (b) The test procedure must insure discovery of all potentially hazardous leaks in the segment being tested.
> (c) The test pressure must be at least 150% of the maximum operating pressure or 50 psi (345 kPa) gauge, whichever is greater. However, the maximum test pressure may not be more than 2.5 times the pressure determined under §192.121 at a temperature not less than the pipe temperature during the test.
> (d) During the test, the temperature of thermoplastic material may not be more than 100 °F (38 °C), or the temperature at which the material's long-term hydrostatic strength has been determined under the listed specification, whichever is greater.

The Department will be looking for records that all plastic piping has been pressure tested to at least 50 psig. Since the federal codes doesn’t specify a test duration, the Department will be looking at whether the company followed its procedures with respect to the duration of the pressure test. Each record, at a minimum, should include the following information: the date of the test, the name(s) of the person(s) performing the test, the name of the specific jurisdictional system tested, the start and stop times of the test, the start and stop pressures of the test, the test medium used, and the results of the test (i.e., leak or no leak).

18. Do records indicate determination of the MAOP of pipeline segments in accordance with 192.619 and limiting of the operating pressure as required?

> §192.619 Maximum allowable operating pressure: Steel or plastic pipelines.
> (a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure determined under paragraph (c) or (d) of this section, or the lowest of the following:
> (1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part. ….
> (2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:
> (i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.
> ….
> (4) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.

§192.621 Maximum allowable operating pressure: High-pressure distribution systems.
(a) No person may operate a segment of a high pressure distribution system at a pressure that exceeds the lowest of the following pressures, as applicable:
(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part.
(2) 60 p.s.i. (414 kPa) gage, for a segment of a distribution system otherwise designed to operate at over 60 p.s.i. (414 kPa) gage, unless the service lines in the segment are equipped with service regulators or other pressure limiting devices in series that meet the requirements of §192.197(c).
(3) 25 p.s.i. (172 kPa) gage in segments of cast iron pipe in which there are unreinforced bell and spigot joints.
(4) The pressure limits to which a joint could be subjected without the possibility of its parting.
(5) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressures.
(b) No person may operate a segment of pipeline to which paragraph (a)(5) of this section applies, unless overpressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §192.195.

§192.3 Definitions.
High-pressure distribution system means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer.

For each jurisdictional system, the Department will be looking for an MAOP Determination Worksheet that details how the MAOP was determined for each pipe segment, taking into account the lowest pressure from the methods specified in §§ 192.619 and/or 192.621, as applicable. Section 192.619 is only for steel and plastic pipelines (i.e., not copper), while 192.621 pertains to all types of pipelines in a high-pressure distribution system [although not explicit in the text of Question 18, the PHMSA inspection form references code sections 192.619(a), 192.619(b), 192.621(a), 192.621(b), 192.623(a), and 192.623(b) for this question]. The Department would be looking for backup documentation for each element used in the MAOP Determination Worksheet.

A PHMSA interpretation provides:
"Section 192.619(a) prescribes the maximum allowable operating pressure for all steel and plastic pipelines. Section 192.621(a) prescribes additional limitations which apply to pipelines in high pressure distribution systems. In order to establish a maximum allowable operating pressure for a high pressure distribution pipeline, you must comply with the requirements of both sections."

The Department considers jurisdictional propane systems to be high-pressure distribution systems because the pressures in the tank segment and the first stage are higher than the pressure provided to the customer. The Department expects operators of jurisdictional systems to have, for each jurisdictional system, an MAOP Determination Worksheet that clearly specifies the MAOP for each pipeline segment of the system in accordance with the criteria of §§ 192.619 and/or 192.621, as applicable. If the system has been transferred from a previous operator and the MAOP Determination Worksheet did not transfer, it is up to the current operator to determine the MAOP of the pipeline segments, and this may involve conducting pressure tests in

accordance with 192 Subpart J, as applicable. [See also interpretation PI-74-0120 March 11, 1974 with respect to pressure-test record keeping pursuant to 192.517:
"It is important to note that the natural Gas Pipeline Safety Act of 1968 places the obligation of compliance with the Federal gas pipeline safety standards on each person who transports gas or who owns or operates pipeline facilities. This obligation may not be excused by blaming previous owners or operators for any failure in compliance."]

Periodic Patrols, Surveys, and Tests

For operations and maintenance activities, records must be retained as follows:

> §192.603 General provisions.
> (b) Each operator shall keep records necessary to administer the procedures established under §192.605 [Procedural manual for operations, maintenance, and emergencies].

Each record, at a minimum, should include the following information: the date of the activity, the name(s) of the person(s) performing the activity, the name of the specific jurisdictional system upon which the activity was performed, any necessary data to understand what was performed, the results of the activity, and any recommended or necessary follow-up activities based upon the results.

19. Do records indicate that ROW surface conditions have been patrolled as required?

> §192.721 Distribution systems: Patrolling.
> (a) The frequency of patrolling mains must be determined by the severity of the conditions which could cause failure or leakage, and the consequent hazards to public safety.
> (b) Mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage must be patrolled—
> (1) In business districts, at intervals not exceeding 4 1⁄2 months, but at least four times each calendar year; and
> (2) Outside business districts, at intervals not exceeding 7 1⁄2 months, but at least twice each calendar year.

Subsection (a) above states that it is the operator that generally determines the frequency of patrolling due to the conditions in the field. The operator should include this patrolling frequency in its procedures. The Department will be looking for records demonstrating the operator followed its procedures with respect to patrolling.

Subsection (b) above requires a patrolling frequency for the special case "where anticipated physical movement or external loading could cause failure or leakage." The operator should identify which, if any, jurisdictional systems fall into this category and then perform the patrolling according to (b)(1) or (2) above, depending on whether the system is within a business district. For these systems, the Department will be looking for records indicating the system was patrolled as required by federal code.

Note: PHMSA has provided interpretations for the definition of a business district. In PI-95-002, PHMSA states "Part 192 does not define the term "business district." However, by its plain meaning, the term refers to a place whose primary function is the conduct of business." In PI-75-002, PHMSA states: "A business district is an area containing shops and offices where persons engage in the purchase and sale of commodities or in related financial transactions." The Department will consider a jurisdictional system serving one or more businesses to be in a business district.

20. Do records indicate distribution leakage surveys were conducted as required?

§192.723 Distribution systems: Leakage surveys.
(a) Each operator of a distribution system shall conduct periodic leakage surveys in accordance with this section.
(b) The type and scope of the leakage control program must be determined by the nature of the operations and the local conditions, but it must meet the following minimum requirements:
(1) A leakage survey with leak detector equipment must be conducted in business districts, 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.
(2) A leakage survey with leak detector equipment must be conducted outside business districts as frequently as necessary, but at least once every 5 calendar years at intervals not exceeding 63 months. However, for cathodically unprotected distribution lines subject to §192.465(e) on which electrical surveys for corrosion are impractical, a leakage survey must be conducted at least once every 3 calendar years at intervals not exceeding 39 months.

PHMSA's *Guidance Manual for Operators of LP Gas Systems* states: "Numerous LP gas operators opt to do a pressure drop test to prove the integrity of their pipeline. This is normally done on smaller systems, where shutting off the customers is not a problem. A very important thing to consider is, if you do have any drop in pressure, then you shall do a subsurface survey using a CGI meter to pinpoint the leak. …. Pressure used during the test should be at least equal to the operating pressure. …. An advantage of doing this type of test is that the first stage regulator can be tested for lock up at the same time." (See the next question pertaining to regulator inspection and testing.) Note: this pressure-drop leak test will not satisfy the pressure test for MAOP determination (see above section "Pressure Testing and MAOP Determination") unless performed at sufficient pressure in accordance with Subpart J (Test Requirements) of Part 192 and §192.619.

The Department will be looking for records indicating that either pressure-drop tests or leak surveys have been conducted at the specified intervals defined in 192.723. For the pressure-drop test method, each record, at a minimum, should include the following information: the date of the test, the name(s) of the person(s) performing the test, the name of the specific jurisdictional system tested, the start and stop times of the test, the start and stop pressures of the test, the test medium used, and the results of the test (i.e., leak or no leak). If the Company uses the subsurface survey using a CGI meter, then each record, at a minimum, should include the following information: the date of the survey, the name(s) of the person(s) performing the survey, the name of the specific jurisdictional system surveyed, a map of the system showing the locations of the survey points, and the results of the survey (i.e., leak or no leak).

21. Do records indicate inspection and testing of pressure limiting, relief devices, and pressure regulating stations as required and at the specified intervals?

§192.739 Pressure limiting and regulating stations: Inspection and testing.

(a) Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is—

(1) In good mechanical condition;

(2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

(3) Except as provided in paragraph (b) of this section, set to control or relieve at the correct pressure consistent with the pressure limits of §192.201(a); and

(4) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

Regulator stations must be inspected and tested using any practicable method that will demonstrate compliance with §192.739. Set-point, lock-up, and full-stroke-operation would be part of the inspection and testing if such tests are practicable at the station.

Practicable inspections and tests do not require the operator to disassemble the regulator, re-pipe the regulator, or cut off the supply of gas to the system. Instead, we suggest that, as a minimum, these service-type regulators be visually inspected, be checked for leaks (including the regulator vent), and be checked for correct set-point. Verifying the correct setpoint on a service-type regulator can be done by measuring the pressure of the gas (downstream of the regulator) with a pressure gauge.

The Department will be looking for records documenting the testing has been performed on the operator's jurisdictional system(s) equipment, as specified in the regulation, at the frequency required by code. Good mechanical condition, adequate capacity, reliability, and installation documentation will be expected to be available as a part of verifying regulation is being met.

As part of this annual inspection, the person performing the inspection should record the make and model of the regulator that is installed in the field, which will also satisfy one of the requirements of the following question.

22. Do records indicate testing or review of the capacity of each pressure relief device at each pressure limiting station and pressure regulating station as required and a new or additional device installed if determined to have insufficient capacity?

§192.743 Pressure limiting and regulating stations: Capacity of relief devices.

(a) Pressure relief devices at pressure limiting stations and pressure regulating stations must have sufficient capacity to protect the facilities to which they are connected. Except as provided in §192.739(b), the capacity must be consistent with the pressure limits of §192.201(a). This capacity must be determined at intervals not exceeding 15 months, but at least once each calendar year, by testing the devices in place or by review and calculations.

(b) If review and calculations are used to determine if a device has sufficient capacity, the calculated capacity must be compared with the rated or experimentally determined relieving capacity of the device for the conditions under which it operates. After the initial calculations, subsequent calculations need not be made if the annual review documents that parameters have not changed to cause the rated or experimentally determined relieving capacity to be insufficient.

(c) If a relief device is of insufficient capacity, a new or additional device must be installed to provide the capacity required by paragraph (a) of this section.

[NFPA 58] 5.7.3.6 First-stage regulators shall incorporate an integral pressure relief valve having a start-to-discharge setting within the limits specified in UL 144, Standard for LP-Gas Regulators.
5.7.3.7 First-stage regulators with a rated capacity of more than 500,000 Btu/hr (147 kW/hr) shall be permitted to have a separate pressure relief valve.
…
5.7.3.9 First-stage regulators shall have an outlet pressure setting up to 10.0 psig (69 kPag) in accordance with UL 144, Standard for LP-Gas Regulators.

A 1997 PHMSA Final Order addressed the relationship between §192.743 and NFPA 58 Section 5.7.3 as follows:

The Notice Item 8 alleged that Respondent had violated 49 C.F.R. § 192.743, by failing to do calculations if testing of relief devices is not feasible. Specifically, Respondent did not have procedures in place for testing of the pressure regulating valves, therefore it was not conducting tests, and was not doing the required calculations. However, NFPA 58/59 only requires that these regulators be UL 144 approved and does not require further testing or calculations.

According to 49 C.F.R. § 192.11(c), if there is a conflict between that part (Part 192) and ANSI/NFPA 58/59, ANSI/NFPA 58/59 will prevail. Since Part 192 requires testing or calculations and NFPA 58/59 does not, there exists a conflict therefore, the NFPA standard prevails. Respondent has complied with the NFPA standard. Therefore, this allegation of violation is withdrawn.

Based on the above, the Department will be looking for documentation that all regulators in place between the tank(s) and up to and including the first stage regulator(s) are compliant with UL 144 (Standard for Safety: LP-Gas Regulators). If the operator is unable to produce records indicating UL 144 compliance, then the Department will be looking for compliance with §192.743 in the form of records demonstrating regulators and/or relief devices have sufficient relief capacity, and that this capacity is determined at intervals not exceeding 15 months, but at least once each calendar year, by testing the devices in place or by review and calculations. For UL 144 and §192.743 review and calculations, the company is required to check the device in the field to make sure it matches what is recorded to be there (see question # 21 pertaining to 192.739).

23. Do records indicate proper inspection and partial operation of each distribution system valve that might be required in an emergency at intervals not exceeding 15 months, but at least once each calendar year, and prompt remedial action to correct any valve found inoperable?

§192.747 Valve maintenance: Distribution systems.
(a) Each valve, the use of which may be necessary for the safe operation of a distribution system, must be checked and serviced at intervals not exceeding 15 months, but at least once each calendar year.

> (b) Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.

The Department will be looking for documentation showing that key valves in each jurisdictional system have been checked and operated at least once each calendar year not to exceed 15 months. The purpose of this inspection is to ensure valves are in good workable condition in the event of an emergency. For any valve deficiencies noted in the inspection records, the Department will be looking for a record that prompt remedial action was performed to correct the deficiencies.

Abandoning and Reinstating Pipelines

For operations and maintenance activities, records must be retained as follows:

§192.603 General provisions.
(b) Each operator shall keep records necessary to administer the procedures established under §192.605 [Procedural manual for operations, maintenance, and emergencies].

24. From the review of records, did the operator properly test disconnected service lines?

§192.725 Test requirements for reinstating service lines.
(a) Except as provided in paragraph (b) of this section, each disconnected service line must be tested in the same manner as a new service line, before being reinstated.
(b) Each service line temporarily disconnected from the main must be tested from the point of disconnection to the service line valve in the same manner as a new service line, before reconnecting. However, if provisions are made to maintain continuous service, such as by installation of a bypass, any part of the original service line used to maintain continuous service need not be tested.

Have any of the jurisdictional systems being inspected been disconnected and reinstated? If not, this question is not applicable. If so, the Department will be looking for records showing that disconnected service lines have been tested prior to being brought back into service.

25. Do records indicate pipelines and facilities were abandoned or deactivated in accordance with requirements?

§192.727 Abandonment or deactivation of facilities.
(a) Each operator shall conduct abandonment or deactivation of pipelines in accordance with the requirements of this section.
(b) Each pipeline abandoned in place must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.
(c) Except for service lines, each inactive pipeline that is not being maintained under this part must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.
(d) Whenever service to a customer is discontinued, one of the following must be complied with:
(1) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.
(2) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.
(3) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

(e) If air is used for purging, the operator shall insure that a combustible mixture is not present after purging.
(f) Each abandoned vault must be filled with a suitable compacted material.

Have any of the jurisdictional systems being inspected been abandoned or deactivated? If not, this question is not applicable. If so, the Department will be looking for records indicating the service was properly abandoned or deactivated using the specifications outlined in 192.727.

Field Inspections

The Department will typically conduct a field inspection in conjunction with a records inspection to view in the field the systems that were inspected for records. The field inspection will be conducted to determine compliance of the physical facilities with respect to 49 CFR Part 192, NFPA 58, and NFPA 59, as applicable. As explained in the Introduction, the format of the Field Inspections section in this document is different than that of the Records Inspections section due to the variability of system configurations in the field. The Department's field inspection form (included as Appendix E) is comprised of a checklist of *typical* items to inspect, but is not exhaustive of all of the requirements of 49 CFR Part 192, NFPA 58, and NFPA 59 (the field inspection form does not currently include questions pertaining to NFPA 59), as the physical nature of the facilities in the field will determine which requirements are applicable, and it would be too cumbersome to go through all of the NFPA sections here. The field inspection form also includes a section to write in any other findings that may not be included in the checklist. The conditions in the field will determine which code sections are applicable, regardless of whether they appear on the Department's inspection form.

A few common items found on field inspections are:

* Tanks and/or aboveground facilities (regulators, meters, piping) are not adequately protected from vehicular damage or other outside forces (such as falling ice).

* The make and/or model of the regulators in the field are either unreadable or do not match the records for the system.

* Insufficient height of regulators such that snow accumulation could block the relief vent and affect its operation.

* Above-ground piping not adequately cleaned and coated to protect against atmospheric corrosion.

The applicable codes sections for the items listed above, and for other items typically inspected, are included in the inspection form contained in Appendix E. If, after reviewing the inspection form in Appendix E, the propane operators would like the Department to clarify what will be looked for during a field inspection, please provide this feedback, and it will be included in this section of the next update to the guidance document.

Appendix A: Determination of Whether a Propane System is Jurisdictional

The federal pipeline safety code (49 CFR Part 192) doesn't affirmatively state which propane systems are subject to its jurisdiction, but rather specifies which systems are not subject to its jurisdiction:

> §192.1 What is the scope of this part?
> (a) This part prescribes minimum safety requirements for pipeline facilities and the transportation of gas, including pipeline facilities and the transportation of gas within the limits of the outer continental shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).
> (b) This part does not apply to—
> ….
> (5) Any pipeline system that transports only petroleum gas or petroleum gas/air mixtures to—
> (i) Fewer than 10 customers, if no portion of the system is located in a public place; or
> (ii) A single customer, if the system is located entirely on the customer's premises (no matter if a portion of the system is located in a public place).

Based on the above code section, the Department has developed the following table specifying which types of propane systems are and are not subject to the jurisdiction of 49 CFR Part 192:

Number of Customers	Portion of System in a Public Place?	
	Yes	No
1 (system located entirely on customer premises)	Non-jurisdictional	Non-jurisdictional
1 (system not located entirely on customer premises)	Jurisdictional	Non-jurisdictional
2 - 9	Jurisdictional	Non-jurisdictional
10 or more	Jurisdictional	Jurisdictional

"Public place" is defined in PHMSA's *Guidance Manual for Operators of LP Gas Systems* as "A place that is generally open to all persons in a community as opposed to being restricted to specific persons. Examples of public places include churches, schools, and commercial buildings, as well as any publicly owned right-of-way or property frequented by a person."

"Customer" is defined in the Guidance Manual as "An end user who has control of the gas usage." Per PHMSA Interpretation PI-11-0009, the number of customers is not necessarily the same as the number of meters.

Each year, as part of the Annual Inquiry issued by the Department, each operator of one or more jurisdictional propane systems is required to submit to the Department a list of those jurisdictional systems it operates. It is the responsibility of each operator to understand the definition of a jurisdictional system and to determine which of its systems are in fact jurisdictional. If the operators have any questions regarding the determination of whether a system is jurisdictional, please contact the Department, and we would be happy to help.

Appendix B: Jurisdiction of NFPA 58 Versus NFPA 59

NFPA 58	NFPA 59
1.3.1 Application of the Code. This code shall apply to the operation of all LP-Gas systems including the following: (1) Containers, piping, and associated equipment, when delivering LP-Gas to a building for use as a fuel gas. (2) Highway transportation of LP-Gas. (3) The design, construction, installation, and operation of marine terminals whose primary purpose is the receipt of LP-Gas for delivery to transporters, distributors, or users except for marine terminals associated with refineries, petrochemicals, gas plants, and marine terminals whose purpose is the delivery of LP-Gas to marine vessels. (4)*The design, construction, installation, and operation of pipeline terminals that receive LP-Gas from pipelines under the jurisdiction of the U.S. Department of Transportation, whose primary purpose is the receipt of LP-Gas for delivery to transporters, distributors, or users. Coverage shall begin downstream of the last pipeline valve or tank manifold inlet.	**1.1.1*** This code shall apply to the design, construction, location, installation, operation, and maintenance of refrigerated and nonrefrigerated utility gas plants. Coverage of liquefied petroleum gas systems at utility gas plants shall extend to the point where LP-Gas or a mixture of LP-Gas and air is introduced into the utility distribution system. **3.3.17 Systems.** An assembly of equipment that consists essentially of liquefied petroleum gas unloading equipment; a container or containers; major devices such as vaporizers, relief valves, excess-flow valves, and regulators; and interconnecting piping. In the case of refrigerated storage, it also includes compressors, condensers, and other related equipment and controls. Such systems include any unloading equipment, storage equipment, or interconnecting piping up to the outlet of the first stage regulator, vaporizer, or mixing device, whichever is the last unit before the liquefied petroleum gas enters other plant equipment or distribution lines. **3.3.18*** **Utility Gas Plant.** A plant that stores and vaporizes LP-Gas for distribution that supplies either LP Gas or LP-Gas gas/air mixtures to a gas distribution system of 10 or more customers. **3.3.19 Vaporizer**. A device, other than a container, that receives LP-Gas in liquid form and adds sufficient heat to convert the liquid to a gaseous state.
1.3.2 Nonapplication of Code. This code shall not apply to the following: (1) Frozen ground containers and underground storage in caverns including associated piping and appurtenances used for the storage of LP-Gas. (2) Natural gas processing plants, refineries, and petrochemical plants. (3) LP-Gas (including refrigerated storage) at utility gas plants (*see NFPA 59, Utility LP-Gas Plant Code*). (4) Chemical plants where specific approval of construction and installation plans, based on substantially similar requirements, is obtained from the authority having jurisdiction. (5)*LP-Gas used with oxygen. (6)*The portions of LP-Gas systems covered by NFPA 54 (ANSI Z223.1), *National Fuel Gas Code*, where NFPA 54 (ANSI Z223.1) is adopted, used, or enforced. (7) Transportation by air (including use in hot air balloons), rail, or water under the jurisdiction of the U.S. Department of Transportation (DOT). (8)*Marine fire protection. (9) Refrigeration cycle equipment and LP-Gas used as a refrigerant in a closed cycle. (10) The manufacturing requirements for recreational vehicle LP-Gas systems that are addressed by NFPA 1192, *Standard on Recreational Vehicles*. (11) Propane dispensers located at multiple fuel refueling stations shall comply with NFPA 30A, *Code for Motor Fuel Dispensing Facilities and Repair Garages.*	**1.1.2** When operations that involve the liquid transfer of LP-Gas from the utility gas plant storage into cylinders or portable tanks (as defined by NFPA 58, *Liquefied Petroleum Gas Code*) are carried out in the utility gas plant, these operations shall conform to NFPA 58. **1.1.3** Installations that have an aggregate water capacity of 4000 gal (15.14 m^3) or less shall conform to NFPA58, *Liquefied Petroleum Gas Code*.

Appendix C: VDFA Comments on the Draft Guidance

VFDA
vermontfuel.com

Michelle Laperle, Bill Jordan, and Matt Hecklinger
Vermont Department of Public Service
112 State St.
Montpelier, VT 05602

October 29, 2019

Michelle, Bill and Matt,

Thank you for the the opportunity to provide comments on the document: Guidance to Operators of Jurisdictional LPG Pipeline Systems for Stand Records and Field Inspections. After sharing the document with retailer propane distributors, I received the following feedback:

- ***Looks Good:*** I reviewed and didn't see anything, of concern.
- ***Regarding Odorant Testing:*** Given the previous concerns at DPS, can we get something writing clearly stating that Vermont will accept BOL supplier certification
- ***Regarding Odorant Testing:*** In the past, DPS has accepted it as fact if on the BOL the supplier certified that odorant was added. GC in his last go around stated that the State would not except only the BOL supplier certification. What is the policy now, please clarify.
- ***Looks Good:*** The most difficult thing is to make something simple and it looks like the DPS has succeeded. I particularly like the simple description of MAOP and the easy to follow "Jurisdictional/Non- Jurisdictional" graph.
- ***Page 5:*** The Small Operators Guide Book should also be referenced https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/training/pipeline/56031/revised-guidance-operators-small-lp-gas-systems-april-2017.pdf
- ***Page 6:*** I recommend that the department consider a grace period to allow the operator time to establish the records required by 49 CFR 192.
- ***Page 7:*** It is possible for an LPG system to be installed as a non-jurisdictional system where no CP maps are required. If at some point the system becomes jurisdictional the operator could only create CP maps to the best of their knowledge unless the system is excavated or replaced. I would request that in these scenarios the department recognize maps created to the best of the operators knowledge provided that CP is adequate (ie. anode locations, anode size, etc.)
- ***Page 8:*** We don't have any rectifier OPS systems in the State of VT.

Vermont Fuel Dealers Association — P.O Box 1370, Montpelier, VT 05601
Office: 802-223-7750 — Fax: 802-419-3313 — info@vermontfuel.com — www.vermontfuel.com

- ***Page 8:*** We have no reverse current switches, diodes or interference bonds in VT.
- ***Page 9:*** In reference to low CP readings it is important to note that dry soil conditions may affect CP readings. Because of this our O&M dictates that if low CP readings are found remedial action shall be taken within one year.
- ***Page 10:*** Would coated copper be considered protected as the copper would not be in direct contact with the soil? What about sleeved copper? The testing criteria for copper structures found in appendix D of 49 CFR 192 outlines using negative voltage shift test method. This is not the method used for most operator who currently test buried steel pipelines and tank. This requirement would be difficult and costly for LP operators to implement.
- ***Page 12:*** I am not aware of any regulation in 49 CFR 192 that would require an operator to specify this in writing. Maps should be sufficient.
- ***Page 14:*** The pressure test requirements found in NFPA 58 and 49 CFR 192 are very different. Please note that it is possible for an LP system to be non jurisdictional, and then become jurisdictional simply due to a change in occupancy. This would likely require the operator to perform a new pressure test to be compliant with 192. The department should be cognizant of this.
- ***Page 24:*** The applicable code should be referenced for each of the four items listed below. This would provide the reader the opportunity to read the applicable code section.
- ***Page 26, (Appendix B):*** NFPA 59 is ONLY applicable to installations of 4,001 gallons or more.
- ***Looks Good:*** This helps clarify what they want to see in an inspection.
- ***Pretested Testing Requirement:*** 192 does require all that, I just think asking for test record documentation for a pretested manufactured fitting and relief capacities of UL regulators is a waste to time.
- ***NFPA 59:*** It should be clarified when NFPA 59 will be enforced. The 2004 edition of NFPA 59 in the section for siting containers starts a 2000 gallon tank so I don't see how they can apply that to a system with just 1000 gallons tanks. Also, because NFPA 59 does not allow copper tubing that is a big problem when it comes to a tank farm. All these systems should fall under NFPA 58 only, NFPA 59 should be out of the picture. NFPA 58 covers large container installations and all the operators are familiar with it. NFPA 59 is a Utility code not an LP operator code.

Thanks for your consideration. Please contact me with any questions or concerns.

Matt Cota
Executive Director, Vermont Fuel Dealers Association

Appendix D: Summary Table of Inspection Requirements

	Question	Fed. Code Section	Frequency
1	Location of corrosion control items	49 CFR 192.491(a)	One time (update as needed)
2	Examine exposed buried piping for corrosion	49 CFR 192.459	As needed
3	Cathodic protection monitoring tests	49 CFR 192.465(a)	Once each calendar year, with intervals not exceeding 15 months
4	Electrical checks of rectifiers/impressed current sources	49 CFR 192.465(b)	If applicable, six times each calendar year, but with intervals not exceeding 2 1⁄2 months
5	Electrical checks of interference bonds, diodes, and reverse current switches	49 CFR 192.465(c)	If applicable, six times each calendar year, but with intervals not exceeding 2 1⁄2 months
6	Actions taken to correct identified deficiencies in corrosion control	49 CFR 192.465(d)	As needed
7	Re-evaluation of unprotected buried pipelines for areas of active corrosion	49 CFR 192.465(e)	If active corrosion, every 3 years at intervals not exceeding 39 months
8	Electrical isolation of each buried pipeline from other metallic structures	49 CFR 192.467	As needed
9	Electrical test leads installed in accordance with requirements of Subpart I?	49 CFR §§ 192.469 and 192.471	One time, if applicable
10	Minimize the detrimental effects of stray currents when found	49 CFR 192.473	As applicable
11	Inspection of aboveground pipe for atmospheric corrosion	49 CFR 192.481	Once every 3 calendar years, but with intervals not exceeding 39 months
12	Protection against external corrosion with an adequate coating	49 CFR §§ 192.461 and 192.483	One time, if applicable
13	Repair or replacement of corroded pipe	49 CFR 192.487	As applicable
14	Pressure testing pipelines operated >100 psig	49 CFR 192.507	One time, if applicable
15	Pressure testing pipelines operated below 100 psig (except service lines and plastic pipelines)	49 CFR 192.509	One time, if applicable
16	Pressure testing service lines	49 CFR 192.511	One time, if applicable
17	Pressure testing plastic pipelines	49 CFR 192.513	One time, if applicable
18	MAOP determination	49 CFR §§ 192.619 and 192.621	One time
19	Patrolling ROW surface conditions	49 CFR 192.721	Determined by operator, unless risk of physical movement or external loading, then in business districts at least four times each calendar year with intervals not exceeding 4 1⁄2 months, and outside business districts at least twice each calendar year with intervals not exceeding 7 1⁄2 months
20	Distribution leakage surveys (with leak detector equipment)	49 CFR 192.723	In business districts at least once each calendar year with intervals not exceeding 15 months. Outside business districts, once every 5 calendar years with intervals not exceeding 63 months.
21	Inspection and testing of pressure limiting and relief devices	49 CFR 192.739	Once each calendar year, with intervals not exceeding 15 months
22	Testing or review of relief capacity of each pressure relief device	49 CFR 192.743	Once each calendar year, with intervals not exceeding 15 months
23	Inspection of key valves	49 CFR 192.747	Once each calendar year, with intervals not exceeding 15 months
24	Testing of disconnected service lines	49 CFR 192.725	As applicable
25	Abandoned or deactivated service lines	49 CFR 192.727	As applicable

Appendix E: Field Inspection Form

STANDARD INSPECTION REPORT OF A GAS DISTRIBUTION OPERATOR

Form # VTDPS1010
rev.9/23/2019

Vermont Gas Pipeline Safety Program **Vermont Public Service Department** **112 State Street** **Montpelier VT 05620-2601**				**Inspection date(s):**	
				PHMSA/VTDPS Representative(s):	
PROPANE PIPELINE FIELD INSPECTION					
Name of Operator:				**OPID #:**	
Name of Unit(s):				**Unit #(s):**	
Records Location:					
System Information	**System Name(s):**		**System Location(s):**		
Contact Individual(s)					

49 CFR 192/NFPA 58	PIPELINE INSPECTION (Field)	S	C	U	N/A	N/C
.181	Distribution Valve Placement - *Are Distribution line valves being installed as required of 192.181?*					
.353	Customer Meters and Regulator Location - *Are meters and service regulators being located consistent with the requirements of 192.353?*					
.355	Customer Meters and Regulator Protection - *Are meters and service regulators being protected from damage consistent with the requirements of 192.355?*					
.357	Customer Meters and Regulator - *Are meters and service regulators being installed consistent with the requirements of 192.357?*					
.361	Service Line Installation - *Are customer service lines being installed consistent with the requirements of 192.361?*					
.363 & .365	Service Line Valve and Location Requirements - *Are customer service line valves being installed meeting the valve and locations requirements of 192.363 and 192.365?*					
.379	Service Line Connection Requirements - *Are new customer service lines not in use configured in accordance with the requirements of 192.379?*					
.465(b)	Rectifier or other Impressed Current Sources - *Are impressed current sources properly maintained and are they functioning properly?*					
.467	Isolation from Other Metallic Structures - *Are measures performed to ensure electrical isolation of each buried or submerged pipeline from other metallic structures unless they electrically interconnect and cathodically protect the pipeline and the other structures as a single unit?*					
.471	Test Leads Installation - *Do pipelines with cathodic protection have electrical test leads installed in accordance with requirements of Subpart I?*					
.473	Interference Currents & Impressed Current or Galvanic Anode Systems - *Are areas of potential stray current identified, and if found, the detrimental effects of stray currents minimized? & Are impressed current type cathodic protection systems and galvanic anode systems installed so as to minimize any adverse effect on existing adjacent underground metallic structures?*					
.479	Atmospheric Corrosion Control - *Is pipe that is exposed to atmospheric corrosion protected?*					
.487	Field Inspection – Remedial Actions - *Is Corroded pipe with significant wall loss being replaced?*					
.739/.743	Pressure Limiting and Regulating Stations - *Do regulators and relief devices appear to be in good mechanical condition and protected from dirt, liquids, or other conditions that might prevent proper operation? Do the make and model of regulators and relief devices match the records?*					
.751(a-c)	Prevention of Accidental Ignition - *Perform observations of selected locations to verify that adequate steps have been taken by the operator to minimize the potential for accidental ignition.*					

49 CFR 192/NFPA 58	PIPELINE INSPECTION (Field)	S	C	U	N/A	N/C
6.6.1.1 **6.6.1.4** **6.6.1.5** **6.6.1.6**	Containers – *are containers positioned so the pressure relief valve is in direct communication with the vapor space of the container, are containers painted, are containers installed so that all containers operating appurtenances accessible, are containers securely anchored*					
6.7.2.8	Shut off valve(s) – *shall not be installed between pressure relief devices and the container unless a listed pressure relief valve manifold meeting the requirements of 6.7.2.9 is used*					
6.7.2.1	Pressure Relief Devices - *shall be installed so the relief device is in direct communication with the vapor space of the container*					
6.8.3.9	Piping systems – *including interconnecting of permanently installed containers shall compensate for expansion, contraction, jarring, vibration, and settling*					
6.7.4	First-Stage Regulator Installation – *shall be directly attached or attached by flexible connectors to the vapor service valve of a container, or to a vaporizer outlet, or to interconnecting piping or manifolded containers or vaporizers. Regulators installed downstream of a high-pressure regulators shall be exempt from this requirement. First-stage regulators shall be installed outside of building, except as stated in 6.7.4.3*					
6.13 **6.7.4.4** **6.6.3.6**	Installation in Areas of Heavy Snowfall					
6.8.4.3 **6.8.4.4**	Anodeless Riser, at building & Container • Not backfilled beyond manufactures demarcated line • Check for corrosion at soil to air interface • Minimum 12" of cover (18" if external damage is likely)					
6.8.4.6	Means of Locating Belowground Polyethylene Pipe Check for electrically continuous corrosion resistant tracer wire (minimum AWG 14) or tape must be buried with the pipeline and brought aboveground at building wall or riser.					
6.8.3	Metallic Piping					
6.8.4	Polyethylene Piping					
6.7.4.8	Vent to Building Opening (Horizontally 3 feet) / Combustion Source (5 feet) Tank Relief (distance depends on size of tank) First Stage Relief Second Stage Relief					
6.4.5.2	Combustible Materials (10 feet from Tanks & Appurtenances)					
§192.317 **6.6.1.2** **6.8.3.10**	Protection from Hazards/Outside Force/Vehicular Protection Tanks & Appurtenances Service Regulator/ Meter Sets					

Legend: S = satisfactory, C = concern, U = unsatisfactory, N/A = not applicable, N/C = not checked

Summary of Findings: