CITY OF BLOOMFIELD, IOWA

Operations & Maintenance Plan

Requirements & Recommendations

GAS SYSTEM

OPERATING AND MAINTENANCE PLAN

A Model Plan from the

IOWA ASSOCIATION OF MUNICIPAL UTILITIES

1735 NE 70th Avenue

Ankeny, Iowa 50021-9353

515/289-1999

Disclaimer of Warranty and Limitation of Liability

This model plan has been developed by the Iowa Association of Municipal Utilities to promote the safe operation and maintenance of municipal gas systems and compliance with federal regulation of gas pipeline operators.

This publication is designed to provide accurate and authoritative information in regard to the subject matter covered. It is furnished with the understanding that neither the Association nor its licensed agent is engaged in rendering legal or other professional service. If legal advice or other professional or expert assistance is required, the services of a competent professional person should be sought. This publication is provided "as is" without warranty of any kind, either expressed or implied, including but not limited to the implied warranties of merchantability and fitness for a particular purpose. The entire risk as to the quality, performance, and accuracy of the manual is with the holder.

IOWA
ASSOCIATION OF MUNICIPAL
UTILITIES

Revision #	Date Issued	Adopted by (council/board)	Date Adopted

TABLE OF CONTENTS

DIVISION ONE – REPORTING REQUIREMENTS

DIVISION TWO – GENERAL INFORMATION

DIVISION THREE - MATERIALS

DIVISION FOUR – PIPE DESIGN

DIVISION FIVE – DESIGN OF PIPELINE COMPONENTS

DIVISION SIX – WELDING OF STEEL IN PIPELINES

DIVISION SEVEN – JOINING OF MATERIALS OTHER THAN BY WELDING

DIVISION EIGHT – CONSTRUCTION REQUIREMENTS

DIVISION NINE – CUSTOMER METERS, SERVICE REGULATORS & SERVICE LINES

DIVISION TEN – REQUIREMENTS FOR CORROSION CONTROL

DIVISION ELEVEN – TEST REQUIREMENTS

DIVISION TWELVE - UPRATING

DIVISION THIRTEEN - OPERATIONS

DIVISION FOURTEEN - MAINTENANCE

DIVISION FIFTEEN – QUALIFICATION OF PIPELINE PERSONNEL

DIVISION SIXTEEN – TRANSMISSION PIPELINE INTEGRITY MANAGEMENT (TIMP)

DIVISION SEVENTEEN – DISTRIBUTION PIPELINE INTEGRITY MANAGEMENT (DIMP)

DIVISION EIGHTEEN – DRUG AND ALCOHOL TESTING

CITY OF BLOOMFIELD, IOWA

DIVISION ONE

Reporting Requirements

49 CFR Part 191

Division 1.1: Scope *(Reference 191.1)*

This Division in this Plan details the requirements for annual pipeline reporting, reporting incidents, and the filing of safety-related conditions. This Division also provides a list of additional State and Federal reporting requirements that are not a part of 49 CFR Part 191.

Division 1.2: Definitions *(Reference 191.3)*

The following are definitions that are provided by PHMSA and are referred to in the PHMSA Forms referenced throughout this Division.

Administrator – the Administrator, Pipeline and Hazardous Materials Safety Administration (PHMSA) or his or her delegate.

Confirmed Discovery – When it can be reasonably determined, based on information available to the operator at the time a reportable event has occurred, even if only based on a preliminary evaluation.

Gas – Natural gas, flammable gas, or gas which is toxic or corrosive

Incident – Means any of the following events:

1) 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:
    i. A death, or personal injury necessitating in-patient hospitalization;
    ii. Estimated property damage of $122,000 or more, including loss to the operator and others, or both, **but excluding cost of gas lost**;
    iii. Unintentional estimated gas loss of 3,000,000 cubic feet or more.
2) 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 and incident.
3) An event that is significant in the judgement of the operator, even though it did not meet the criteria of items (1) or (2) listed above.

LNG Facility – A pipeline facility that is used for liquefying natural gas or synthetic gas or transferring, storing, or vaporizing liquified natural gas.

Master Meter System – a pipeline system for distributing gas within, but not limited to, a definable area, such as a mobile home park, housing project, or apartment complex, where the operator purchases metered gas from an outside source for resale through a gas distribution pipeline system. The gas distribution pipeline system supplies the ultimate consumer who either purchases the gas directly through a meter or by other means, such as by rents.

Municipality – A City, County, or any other political subdivision of a State.

Offshore – Beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

Operator – A person who engages in the transportation of gas

Outer Continental Shelf – All submerged lands lying seaward and outside the area of lands beneath navigable waters as defined in Section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

Person – Any individual, firm, joint venture, partnership, corporation, association, State, municipality, cooperative association, or joint stock association, and includes any trustee, receiver, assignee, or personal representative thereof.

Pipeline or Pipeline System – All parts of those physical facilities through which gas moves in transportation, including, but not limited to, pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, deliver stations, holders, and fabricated assemblies.

State – Includes each of the several States, the District of Columbia, and the Commonwealth of Puerto Rico.

Transportation of Gas – The gathering, transmission, or distribution of gas by pipeline, or the storage of gas in or affecting interstate or foreign commerce

Division 1.3: Immediate Notice of Federal Incidents *(Reference 191.5)*

1. Telephonic &/or Electronic Reporting:

1) At the earliest practicable moment following discovery, but no later than 1 hour after **confirmed discovery**, the operator must provide notice to the US Dept of Transportation by dialing **1-800-424-8802** or electronically at www.nrc.uscg.mil of any incident that meets any of the criteria listed below. Complete information of the incident is NOT required to make the initial telephonic or electronic notice to the NRC. The intent of the notice is to notify government agencies at the earliest practicable moment without delay even if all information is not available at that time.
    a) Any event that involves a release of gas from a pipeline that results in a death or personal injury requiring in-patient hospitalization (hospital admission and at least one overnight stay).
    b) Estimated property damage (including operator's facilities and properties of others) of $122,000 or more, **but excluding the cost of gas lost**.
    c) An unintentional estimated gas loss of 3,000,000 cubic feet or more.
    d) Any event that is significant in the judgement of the operator, even though it did not meet the criteria of the items listed above (a - d).

NOTE: Remember to notify the Iowa Utilities Board of any incident reports made to the NRC. See Division 1.5 for specific State reporting criteria.

2) The operator may designate any company personnel to make the report to the NRC as long as the person making the report has the following information available to the NRC.
    a) Name and telephone number of the operator and of the person making the report.
    b) The location of the incident.
    c) The time of the incident.
    d) The number of fatalities and personal injuries, if any.
    e) All other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages.

NOTE: The Federal Incident Notification Worksheet (Guidance Material 1.1) provided on page 15 of this Division may be used as a resource to capture information.

3) Report Confirmation & Revision: Within 48 hours after the *confirmed discovery* of an incident, to the extent practicable, an operator must confirm or update their initial telephonic notice. Updates may include the amount of product released, the amount of property damage, the number of fatalities and injuries, and any other significant facts. If there are no updates to the initial report, the operator must still call and confirm the estimates in its initial report.

(continued on next page)

4) If a telephonic or electronic notice has been made by the operator but then after further investigation, it is determined that incident criteria were NOT met and a written report has NOT been filed, the operator may provide notification to the PHMSA Accident Investigation Division at PHMSAaccidentinvestigationdivision@dot.gov.

2. Written Reporting Requirements *(Reference 191.7, 191.9 & 191.15)*

1. Distribution System: Written Incident Report

1) The operator of a distribution system must submit a written report as soon as practicable but not more than 30 days after the telephonic or electronic notification of an incident. DOT Form RSPA F 7100.1 shall be completed and filed electronically with PHMSA at https://portal.phmsa.dot.gov/pipeline.
2) When or if additional relevant information is obtained after the initial report is submitted, the operator shall make supplemental reports as deemed necessary with a clear reference by date and subject to the original report.
3) Master meter operators are not required to submit an incident report.

*** Additional instructions and report forms can be downloaded from the PHMSA-OPS website at www.phmsa.dot.gov/forms/pipeline-forms

2. Transmission System: Written Incident Report

1) The operator of a transmission system must submit a written report as soon as practicable but not more than 30 days after the detection of an incident. DOT Form RSPA F 7100.2 shall be completed and filed electronically with PHMSA at https://portal.phmsa.dot.gov/pipeline.
2) When additional related information is obtained after an initial report is submitted, the operator must make a supplemental report as soon as practicable with a clear reference by date to the original report.

*** Additional instructions and report forms can be downloaded from the PHMSA-OPS website at www.phmsa.dot.gov/forms/pipeline-forms

NOTE: A copy of all incident reports filed with PHMSA must also be submitted to the Iowa Utilities Board through the Electronic Filing System (EFS).

Guidance Material 1.1

Federal Incident Notification Worksheet

Date of Incident:____________________________ Time of Incident:____________________________

Location of Incident:____

____

Facilities Involved:____

____

____

Injuries or Fatalities:____

____

Description of Incident:____

____

____

____

Customers/Suppliers Affected:____

____

Emergency Action Taken:____

____

____

Other Significant Facts:____

____

Date & Time of Report to National Response Center:____

Method of Report (phone or email):____

Name and Phone Number of Person Making Report to NRC:____

____

24 HR Telephone Number Provided to NRC:____

Report Number Assigned by NRC:____

Division 1.4: Incident Reporting, Retracting a 30-Day Written Notice

(Reference 191.7, 191.9 & 191.15)

Retracting a 30-Day Written Notice: An operator who files a written incident report according to procedures listed in Division 1.3 (2), Immediate Notice of Federal Incidents; Written Reporting Requirements, and upon further investigation determines that the event did **NOT** meet criteria required to be defined as an incident, may request that the report be retracted. Requests to retract a 30-day written report are to be emailed to InformationResourcesManager@dot.gov. The request must include the following information;

1) The Report ID (the unique 8-digit identifier assigned by PHMSA).
2) Operator name.
3) OPID number.
4) The number assigned by the National Response Center (NRC) from when the telephonic notice of the event was made. If supplemental calls/reports were made to the NRC for the event, list all supplemental report numbers assigned by the NRC.
5) Date of the event.
6) Location of the event.
7) A brief statement as to why the report should be retracted.

NOTE: This request for retracting a 30-day written report must also be submitted to the Iowa Utilities Board through the Electronic Filing System (EFS).

Division 1.5: Immediate Notice of State Incidents

1. Telephonic Reporting to the Iowa Utilities Board:

(Reference Iowa Code 199 19.17(1)(2))

1) **A notice shall be given immediately, or as soon as practical (preferably within 1 hour of discovery)** of any event involving the release of gas, failure of equipment, or interruption of facility operations, which results in any of the following:
   a) A death or personal injury requiring in-patient hospitalization (hospital admittance and at least one overnight stay).
   b) Estimated property damage of $15,000 or more to the property of the utility or others **including** the cost of gas lost.
   c) Any unplanned interruption of service which extinguishes the pilot lights of 50 or more customers in one segment of a distribution system.
   d) Any MAOP exceedance event occurring in a distribution system.
   e) Any other incident considered being significant by the utility. Example: Any condition that receives media attention, but not meeting reporting criteria listed above.
2) If the incident meets one of the criteria listed above, the Iowa Utilities Board shall be notified by telephone by contacting the **Board Duty Officer** at **515-745-2332** or electronically at dutyofficer@iub.iowa.gov. If the Board Duty Officer does not answer, leave a call back number for a person who is knowledgeable of the incident. The following information should be readily available to the Duty Officer or stated through electronic communications;

NOTE: The State Incident Notification Worksheet (Guidance Material 1.2) provided on page 19 of this Division may be used as a resource to capture the following information.

   a) The name of the utility, the name and telephone number of the person making the report, and the name and telephone number of a contact person knowledgeable about the incident.
   b) Location and time of the incident.
   c) The number of fatalities or injuries, including the extent of the injuries.
   d) Initial damage estimates.
   e) A summary of the significant information available to the utility regarding the probable cause and the extent of damages.
   f) Any oral or written report required by US Dept of Transportation and the name of the person who made the oral or written report.

Reminder: Any event requiring telephonic notice to the US Dept of Transportation must also be communicated via telephone or email to the Iowa Utilities Board Duty Officer.

(continued on next page)

2. Written Reports to the Iowa Utilities Board:

(Reference Iowa Code 199 19.7(3))

1) A written report must be filed into the Iowa Utilities Board Electronic Filing System within 30 days of the incident. A Docket prefix of "H" followed by the last four digits of the operator's RG# should be used when filing the report into EFS. The written report must include the following information:
   a) The information required from the telephonic notice.
   b) The probable cause of the incident as determined by the utility.
   c) The number and cause of any fatalities or personal injuries requiring in-patient hospitalization.
   d) A detailed description of any property damage and the amount of monetary damages.
2) If significant additional information becomes available at a later date, a supplemental report shall be filed as soon as practicable with clear reference made to the original report.

Guidance Material 1.2

State Incident Notification Worksheet

Date of Incident:_____________________________ Time of Incident:_____________________________

Name of Utility:____

Name and Telephone Number of Person Making Report:____

____

Name and Telephone Number of Person Knowledgeable of Incident:_____________________________

____

Location of Incident:____

____

Injuries or Fatalities (provide extent of injuries):____

____

____

Significant Information and Description of Incident:____

____

____

____

Customers Affected:____

____

Initial Damage Estimates:____

____

Date & Time of Report Made to IUB Duty Officer:____

Method of Report (phone or email):____

Was notification made to the National Response Center?____

If so, by whom? ____

Division 1.6: Annual Reporting Requirements - Federal

(Reference 191.11, 191.13 & 191.17)

1. Annual Report for Calendar Year, Gas Distribution System: PHMSA Annual Report F 7100.1-1

a) Each operator of a distribution system must submit the annual report DOT Form PHMSA F 7100.1-1 no later than March 15 for the preceding calendar year. This report will contain information gathered during the previous calendar year. **Example;** 2019 Annual Report due by March 15, 2020 will contain data from calendar year 2019.
NOTE: *When figuring for lost and unaccounted for gas for the previous year, it must be figured using data from July 1 to June 31, not by calendar year.*

b) PHMSA F 7100.1-1 must be completed and submitted electronically through the PHMSA portal located at https://portal.phmsa.dot.gov/pipeline.

NOTE: Once the PHMSA F 7100.1-1 report has been submitted to PHMSA through the portal, the operator must submit a copy of that report to the Iowa Utilities Board through the Electronic Filing System in a timely manner.

2. Annual Report for Calendar Year, Natural or Other Gas Transmission & Gathering Systems: PHMSA Annual Report F 7100.2-1

a) Each operator of a transmission system must submit the annual report DOT Form PHMSA F 7100.2-1 no later than March 15 for the preceding calendar year. This report will contain information gathered during the previous calendar year. **Example;** 2019 Annual Report due by March 15, 2020 will contain data from calendar year 2019.

b) PHMSA F 7100.2-1 must be completed and submitted electronically through the PHMSA portal located at https://portal.phmsa.dot.gov/pipeline.

NOTE: Once the PHMSA F 7100.2-1 report has been submitted to PHMSA through the portal, the operator must submit a copy of that report to the Iowa Utilities Board through the Electronic Filing System in a timely manner.

Division 1.7: National Registry of Pipeline & LNG Operators (OPID)

(Reference 191.7 & 191.22)

1. Operator Identification Number (OPID) Request & Validation

1) Effective January 1, 2012, each operator of a gas pipeline, gas pipeline facility, LNG plant or LNG facility must obtain from PHMSA an Operator Identification Number (OPID). An OPID is assigned to an operator for the pipeline or pipeline system for which the operator is responsible for. To obtain an OPID, an operator must complete an OPID Assignment Request DOT Form PHMSA 1000.1 through the National Registry of Pipeline and LNG Operators, electronically at https://portal.phmsa.dot.gov/pipeline.
2) An operator who has already been assigned one or more OPID by January 1, 2011, must validate the information associated with each OPID through the National Registry of Pipeline and LNG Operators at http://opsweb.phmsa.dot.gov, and correct that information as necessary, no later than June 30, 2012.

2. Notification of Changes:

1) Each operator of a gas pipeline, gas pipeline facility must notify PHMSA electronically at http://opsweb.phmsa.dot.gov, of any the following events not later than 60 days before the event occurs.
    a) Construction or planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe, that costs $10 million or more. If 60-day notice is not feasible because of an emergency, an operator must notify PHMSA as soon as practicable.
    b) Construction of 10 or more miles of a new pipeline.
    c) Construction of a new LNG plant or LNG facility.
2) An operator must notify PHMSA electronically at http://opsweb.phmsa.dot.gov of any of the following events not later than 60 days after the event occurs:
    a) A change in the primary entity responsible for managing or administering a safety program required by 49 CFR Part 191 covering pipeline facilities operated under multiple OPIDs.
    b) A change in the name of the operator.
    c) A change in the entity (company or municipality) that is responsible for an existing pipeline, segment, facility, or LNG facility.
    d) The acquisition or divestiture of 50 or more miles of pipeline subject to Part 192.
    e) The acquisition or divestiture of and existing LNG Plant subject to Part 193.

3. Reporting:

1) An operator must use the PHMSA issued OPID # for all federal reporting requirements.

Division 1.8: Reporting Safety-Related Conditions *(Reference 191.23)*

Each operator shall report in accordance with Division 1.9 of this Plan, the existence of any of the following safety-related conditions involving in-service facilities:

1) In the case of a pipeline (other than an LNG facility) that operates at a hoop stress of 20% or more of its specified minimum yield strength, general corrosion that has reduced the wall thickness to less than that required for the MAOP, and localized corrosion pitting to a degree where leakage might result.
2) Unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability of a pipeline.
3) Any crack or other material defect that impairs the structural integrity or reliability of an underground natural gas facility.
4) Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of 20% or more of its specified minimum yield strength.
5) Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20% or more reduction in operating pressure or shutdown of operation of a pipeline or an LNG facility that contains or processes gas or LNG.
6) For transmission pipelines only, each exceedance of MAOP that exceeds MAOP plus allowable build-up for that pipeline.

A report is **NOT** required for any safety-related condition that-

a) Exists on a master meter system or a customer-owned service line.
b) Is an incident or results in an incident before the deadline for filing the safety-related condition report.
c) Exists on a pipeline (other than an LNG facility) that is more than 220 yards from any building intended for human occupancy or outdoor place of assembly, except that, reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway.
d) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report, except that, reports are required for conditions under paragraph (1) of this section.

NOTE: See table on next page for determination of reporting requirements.

DETERMINATION OF REPORTING REQUIREMENTS FOR SAFETY-RELATED CONDITIONS [1, 2, 3]

<table>
<tr><th>Location</th><th>Time Factor</th><th>Type</th><th colspan="2">Effect on Facility Operation</th><th>Report Required[1]</th></tr>
<tr><td rowspan="20">Within 220 yards of a building intended for human occupancy or outdoor place of assembly or within the right-of-way of an active railroad, paved road, street or highway</td><td rowspan="14">Will not be corrected within 5 working days [3] after determination <u>or</u> 10 working days [3] after discovery, whichever comes first</td><td rowspan="2">General Corrosion</td><td colspan="2">Causes the MAOP to be reduced</td><td>Yes [4]</td></tr>
<tr><td colspan="2">Does not cause the MAOP to be reduced</td><td>No</td></tr>
<tr><td rowspan="2">Localized Corrosion Pitting</td><td colspan="2">Leakage might result</td><td>Yes [4]</td></tr>
<tr><td colspan="2">Leakage unlikely to result</td><td>No</td></tr>
<tr><td rowspan="2">Unintended Movement or Loading</td><td colspan="2">Impairs serviceability</td><td>Yes</td></tr>
<tr><td colspan="2">Does not impair serviceability</td><td>No</td></tr>
<tr><td rowspan="2">Material Defect or Damage</td><td colspan="2">Impairs serviceability</td><td>Yes [4]</td></tr>
<tr><td colspan="2">Does not impair serviceability</td><td>No</td></tr>
<tr><td rowspan="2">Malfunction or Operating Error</td><td colspan="2">Causes pressure to increase above MAOP + allowable buildup</td><td>Yes [2]</td></tr>
<tr><td colspan="2">Does not cause pressure to increase above MAOP + allowable buildup</td><td>No</td></tr>
<tr><td rowspan="2">Leak</td><td colspan="2">Creates an emergency</td><td>Yes</td></tr>
<tr><td colspan="2">Does not create an emergency</td><td>No</td></tr>
<tr><td rowspan="2">All Other Conditions</td><td colspan="2">Could lead to an imminent hazard and causes
a) 20% or more pressure reduction <u>or</u>
b) shutdown</td><td>Yes</td></tr>
<tr><td colspan="2">All others</td><td>No</td></tr>
<tr><td rowspan="6">Will be corrected within 5 working days [3] after determination <u>or</u> 10 working days [3] after discovery, whichever comes first</td><td rowspan="2">General Corrosion</td><td colspan="2">Causes the MAOP to be reduced</td><td>Yes [4]</td></tr>
<tr><td colspan="2">Does not cause the MAOP to be reduced</td><td>No</td></tr>
<tr><td rowspan="3">Localized Corrosion Pitting</td><td rowspan="2">Leakage might result</td><td>Effectively coated & cathodically protected</td><td>No</td></tr>
<tr><td>All other coating/cathodic protection conditions</td><td>Yes [4]</td></tr>
<tr><td colspan="2">Leakage unlikely to result</td><td>No</td></tr>
<tr><td>All Other</td><td colspan="2">All</td><td>No</td></tr>
<tr><td>All Other Areas</td><td colspan="5">No SRC Report Required, however, see Note 2 below.</td></tr>
</table>

<u>Notes:</u>

[1] An event which has been reported as an incident (§191.5) is not reportable as a safety-related condition. Report is not required for any safety-related condition that exists on a master meter system or a customer-owned service line.

[2] For transmission facilities that have exceeded MAOP plus buildup allowed for operation of pressure limiting or control devices, an MAOP Exceedance Report is required to be reported within 5 calendar days. All such MAOP exceedances on transmission facilities must be reported regardless of location or time factor relative to condition correction, See guide material under §191.23.

[3] Working day does not include Saturday, Sunday, or federal holidays.

[4] Does not pertain to pipelines operating at less than 20% SMYS.

Division 1.9: Filing Safety-Related Condition Reports *(Reference 191.25)*

1) Each report of a safety-related condition meeting the requirements of Division 1.8 of this Plan, must be filed (received by OPS within five working days, not including Weekends or Federal Holidays) after the day a representative of the operator first determines that the condition exists, but not later than 10 working days after the day a representative of the operator discovers the condition. Separate conditions may be described in a single report if they are closely related.
2) Reports of transmission MAOP exceedance must be filed in writing within 5 calendar days of the exceedance event.
3) Reports must be filed by email to InformationResourcesManager@dot.gov or by fax to 202-366-7128 and contain the following information:
    a) The report must be headed "Safety-Related Condition Report" or "Maximum Allowable Operating Pressure Exceedance".
    b) Name, principal address and OPID# of the operator.
    c) Date of the report.
    d) Name, job title, and business telephone number of the person submitting the report.
    e) Name, job title, and business telephone number of the person who determined that the condition exists.
    f) Date condition was discovered and date condition was first determined to exist.
    g) Location of the condition, with reference to the State (and town, city, or county), and as appropriate, the nearest street address, survey station number, mile post, landmark, or name of the pipeline.
    h) Description of the condition, including circumstance leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored.
    i) The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and completing such action.

NOTE: Any safety-related condition report filed with PHMSA must also be filed with the Iowa Utilities Board through their Electronic Filing System (EFS).

Division 1.10: National Pipeline Mapping System Reporting Requirements

(Reference 191.7 & 191.29)

Each operator of a gas transmission pipeline or LNG facility must provide the following geospatial data to PHMSA for that pipeline or facility:

1) Geospatial data, attributes, metadata and transmittal letter appropriate for use in the National Pipeline Mapping System. Acceptable formats and additional information are specified in the NPMS Operator Standards Manual available at www.npms.phmsa.dot.gov or by contacting the PHMSA Geographic Information Systems Manager at 202-366-4595.
2) The name and the address for the operator.
3) The name and contact information of a pipeline company employee, to be displayed on a public Website, who will serve as a contact for questions from the general public about the operator's NPMS data.
4) The information required from paragraph (1) above must be submitted each year, on or before March 15, representing assets as of December 31 of the previous calendar year. If no changes have occurred since the previous year submission, follow the procedure below to update NPMS as required or refer to the guidance provided in the NPMS Operator Standards Manual available at www.npms.phmsa.dot.gov or by contacting the PHMSA Geographic Information Systems Manager at 202-366-4595:
    i. Visit the website www.npms.phmsa.dot.gov/OSAVE and log into the system using your PIMMA login information.
    ii. Review the pipeline data currently in the NPMS national layer for your OPID via a web map viewer.
    iii. View the NPMS pipeline submission history for your OPID.
    iv. Update information, if required, for your OPID's pipeline-related primary, technical, and public contacts.
    v. Convey a notification of no changes for pipelines.
5) For additional information regarding Operator Submission And Validation Environment (OSAVE), please refer to the OSAVE Users Guide located at www.npms.phmsa.dot.gov.

NOTE: The annual NPMS filing must also be filed with the Iowa Utilities Board through their Electronic Filing System (EFS).

Division 1.11: Additional Reporting Requirements

The following is a list of additional reports that are required to be submitted to stay in compliance with State and Federal Regulations, but are not required by 49 CFR Part 191.

All of the following reports can be accessed via the Iowa Association of Municipal Utilities website at www.iamu.org. The reports can be found by clicking on Services, then Gas, then Annual Reporting Calendar.

Required for all municipally owned gas utilities:

1) EIA-176, Annual Report of Natural and Supplemental Gas Supply and Disposition is required by the Energy Information Administration, must be filed in the Iowa Utilities Board Electronic Filing System and must be completed by March 1 of each calendar year unless notified otherwise.
2) Municipal Transfer Replacement Tax Return must be submitted to the City Chief Financial Officer no later than March 31 of each calendar year.
3) Statewide Property Tax Return must be submitted to the Iowa Department of Revenue by March 31 of each calendar year. If your utility is required to complete this form, you will receive it in the mail from the Iowa Department of Revenue.
4) Replacement Tax Form B must be submitted to the Iowa Department of Revenue by March 31 of each calendar year.
5) Annual Report for Municipal Gas Plant and Operations (MG-1) must be completed and submitted electronically each calendar year no later than April 1, through the Iowa Utilities Board website and Electronic Filing System.
6) Replacement Tax Form C must be completed by May 1 of each calendar year and is required by the Iowa Department of Revenue.
7) FERC 552 Form – Annual Report of Natural Gas Transactions is required to be completed by May 1 of each calendar year by the Federal Energy Regulatory Commission for any utility that purchases or sales are equal to or greater than 2.2 trillion Btu's during the reporting period.
8) Municipal Utility Transfer Replacement Tax Rate Calculation Form is required by the Iowa Department of Revenue and is due by August 31 each calendar year.
9) Customer Contribution Fund Activity Report is due by September 30 of each calendar year and is required by the Iowa Utilities Board.
10) Estimated Replacement Taxes is required by the Iowa Department of Revenue and is due by October 1 of each calendar year.
11) Railroad and Utility Emergency Contact Information must be updated or submitted to the Iowa Utilities Board within a timely manner, anytime significant personnel changes have been made. This must be completed electronically through the Iowa Utilities Board website.

Division 1.12: Railroad & Utility Emergency Contact Information *(Reference: Iowa Code section 476.27)*

If the Operator has any pipeline facilities crossing a railroad right-of-way, it is required by Iowa Code 476.27 that the Operator log onto the Iowa Utilities Board website (www.iub.iowa.gov), complete and electronically submit the "Emergency Contact Information for Public Utilities" form.

The Operator may also view any emergency contact information provided by railroads in case the Operator needs to contact the railroad for any nonroutine maintenance or emergency repairs that need to be made in the railroad right-of-way.

NOTE: This information must be updated through the Iowa Utilities Board website anytime there are personnel changes or contact information changes that differ from the previous submission.

CITY OF BLOOMFIELD, IOWA

DIVISON TWO

General Information

49 CFR Part 192 Subpart A

Division: 2.1: Definitions *(Reference 192.3)*

The following are definitions provided by PHMSA and are used throughout 49 CFR Part 192 as well as this Plan.

Abandoned – means permanently removed from service.

Active Corrosion – means the continuing corrosion that, unless controlled, could result in a condition that is detrimental to public safety.

Administrator – means the Administrator, Pipeline and Hazardous Materials Safety Administration or his or her delegate.

Alarm – means an audible or visible means of indicating to the controller that equipment or processes are outside operator-defined, safety related protocol.

Control Room – means an operations center staffed by personnel charged with the responsibility for remotely monitoring and controlling a pipeline facility.

Controller – means a qualified individual who remotely monitors and controls the safety-related operations of a pipeline facility via a SCADA system from a control room, and who has operational authority and accountability for the remote operational functions of the pipeline facility.

Customer Meter – means the meter that measures the transfer of gas from and operator to a consumer.

Distribution Line – means a pipeline other than a gathering line or transmission line.

Electrical Survey – means a series of closely spaced pipe-to-soil readings over pipelines which are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline.

Exposed Underwater Pipeline – means an underwater pipeline where the top of the pipe protrudes above the underwater natural bottom (as determined by recognized and generally accepted practices) in waters less than 15 feet deep, as measured from mean low water.

Gas – means natural gas, flammable gas, or gas which is toxic or corrosive.

Hazard to Navigation – means a pipeline where the top of the pipe is less than 12 inches below the underwater natural bottom (as determined by recognized and generally accepted practices) in waters less than 15 feet deep, as measured from the mean low water.

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.

Line Section – means a continuous run of transmission line between adjacent compressor stations, between a compressor station and storage facilities, between a compressor station and a block valve, or between adjacent block valves.

Low-Pressure Distribution System – means a distribution system in which the gas pressure in the main is substantially the same as the pressure provide to the customer.

Main – means a distribution line that serves as a common source of supply for more than one service line.

Maximum Actual Operating Pressure – means the maximum pressure that occurs during normal operations over a period of 1 year.

Maximum Allowable Operating Pressure (MAOP) – means the maximum pressure at which a pipeline or segment of a pipeline may be operated.

Moderate Consequence Areas – means an onshore area that is within a potential impact circle containing either of the following:

a) 5 or more buildings intended for human occupancy, or
b) Any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, as defined in the Federal Highway Administration's Highway Functional Classification Concepts, Criteria and Procedures, and does NOT meet the definition of a high consequence area.

Municipality – means a city, county, or any other political subdivision of a State.

Offshore – means beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

Operator – means a person who engages in the transportation of gas.

Person – means any individual, firm, joint venture, partnership, corporation, association, State, municipality, cooperative association, or joint stock association, and including any trustee, receiver, assignee, or personal representative thereof.

Petroleum Gas – means propane, propylene, butane, (normal butane or isobutanes), and butylene (including isomers), or mixtures composed predominantly of these gases having a vapor pressure not exceeding 208 psi gage at 100° F.

Pipe – means any pipe or tubing used in the transportation of gas, including pipe-type holders.

Pipeline – means all parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.

Pipeline Environment – includes soil resistivity (high or low), soil moisture (wet or dry), soil contaminants that may promote corrosive activity, and other known conditions that could affect the probability of active corrosion.

Pipeline Facility – means new and existing pipelines, rights-of-way, and any equipment, facility, or building used in the treatment of gas during the course of transportation.

Service Line – means a distribution line and 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.

Service Regulator – means the device on a service line that controls the pressure of gas delivered from a higher pressure to the pressure provided to the customer. A service regulator may serve on customer or multiple customers through a meter header or manifold.

Specified Minimum Yield Strength (SMYS)

1) For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or
2) For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with 49 CFR Part 192.107(b).

State – means each of the several States, the District of Columbia, and the Commonwealth of Puerto Rico.

Supervisory Control and Data Acquisition (SCADA) System – means a computer-based system or systems used by a controller in a control room that collects and displays information about a pipeline facility and may have the ability to send commands back to the pipeline facility.

Transmission Line – means a pipeline, other than a gathering line that:

1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center
2) Operates at a hoop stress of 20% or more or SMYS.
3) Transports gas within a storage field.
   NOTE: A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

Transportation of Gas – means the gathering, transmission, or distribution of gas by pipeline or the storage of gas, in or affecting interstate or foreign commerce.

Weak Link – means a device or method used when pulling PE pipe, typically through methods such as HDD, to ensure that damage will not occur to the pipeline by exceeding maximum tensile stress

Welder – means a person who performs manual or semi-automatic welding.

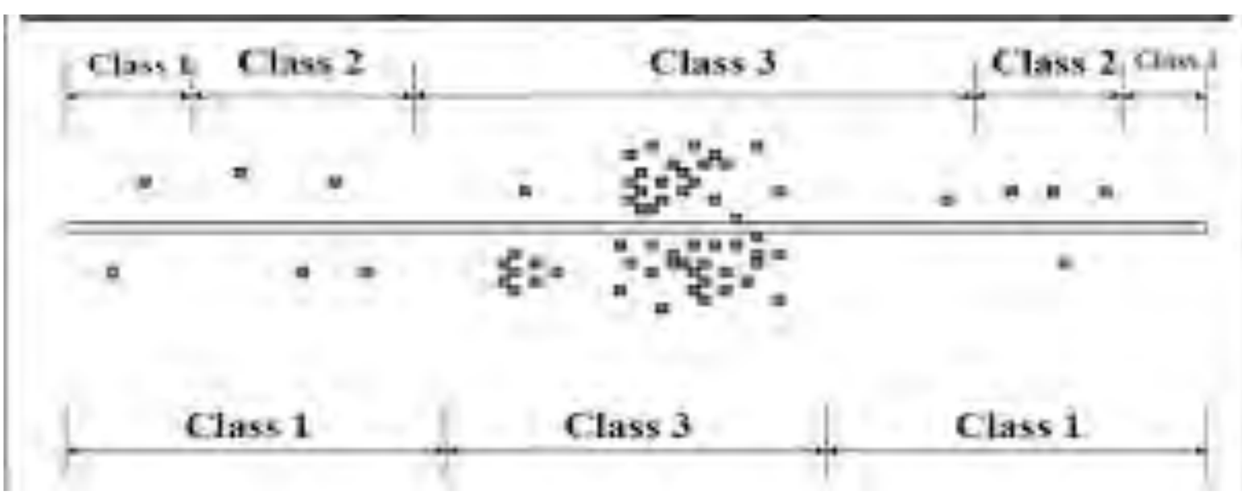
Division 2.2: Class Location Definition *(Reference 192.5)*

Class Location Unit – is an onshore area that extends 220 yards on either side of the centerline of any continuous 1-mile length of pipeline.

Dwelling Unit – Any building intended for human occupancy. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

1) All pipelines and pipeline segments must have a class location determination completed. Pipeline class locations must be determined using the following criteria:
   a) **Class 1**: Any class location unit that has 10 or fewer buildings intended for human occupancy.
   b) **Class 2**: Any class location unit that has more than 10, but fewer than 46 buildings intended for human occupancy.
   c) **Class 3**: Any class location unit that has 46 or more buildings intended for human occupancy, or an area where the pipeline lies within 100 yards of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. The days and weeks do not need to be consecutive.
   d) **Class 4**: Any class location unit where buildings with four or more stories above ground are prevalent.
2) The length of Class locations 2, 3, and 4 may be adjusted as follows:
   a) A Class 4 location ends 220 yards from the nearest building with four or more stories above ground.
   b) When a cluster of buildings intended for human occupancy requires a Class 2 or 3 location, the class location ends 220 yards from the nearest building cluster.
3) The operator must have records that document the current class location of each pipeline segment and that demonstrate how the current locations were determined.

Class location example shown below



Division 2.3: Reference Documents *(Reference 192.7)*

(a) This Division lists all of the reference documents that are incorporated by reference partly or wholly by 49 CFR Part 192. The materials listed in this section have the full force of law. To enforce any edition other than that specified in this section, PHMSA must publish a notice of change in the FEDERAL REGISTER.

(1) *Availability of standards incorporated by reference.* All of the materials incorporated by reference are available for inspection from several sources, including the following:

(i) The Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE., Washington, DC 20590. For more information contact 202-366-4046 or go to the PHMSA Web site at: *http://www.phmsa.dot.gov/pipeline/regs.*

(ii) The National Archives and Records Administration (NARA). For information on the availability of this material at NARA email fedreg.legal@nara.gov or go to www.archives.gov/federal-register/cfr/ibr-locations.html.

(iii) Copies of standards incorporated by reference in this part can also be purchased or are otherwise made available from the respective standards-developing organization at the addresses provided in the centralized IBR section below.

(2) [Reserved]

(b) American Petroleum Institute (API), 1220 L Street NW., Washington, DC 20005, phone: 202-682-8000, *http://api.org/.*

(1) API Recommended Practice 5L1, "Recommended Practice for Railroad Transportation of Line Pipe," 7th edition, September 2009, (API RP 5L1), IBR approved for §192.65(a).

(2) API Recommended Practice 5LT, "Recommended Practice for Truck Transportation of Line Pipe," First edition, March 2012, (API RP 5LT), IBR approved for §192.65(c).

(3) API Recommended Practice 5LW, "Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels," 3rd edition, September 2009, (API RP 5LW), IBR approved for §192.65(b).

(4) API Recommended Practice 80, "Guidelines for the Definition of Onshore Gas Gathering Lines," 1st edition, April 2000, (API RP 80), IBR approved for §192.8(a).

(5) API Recommended Practice 1162, "Public Awareness Programs for Pipeline Operators," 1st edition, December 2003, (API RP 1162), IBR approved for §192.616(a), (b), and (c).

(6) API Recommended Practice 1165, "Recommended Practice for Pipeline SCADA Displays," First edition, January 2007, (API RP 1165), IBR approved for §192.631(c).

(7) API Specification 5L, "Specification for Line Pipe," 45th edition, effective July 1, 2013, (API Spec 5L), IBR approved for §§192.55(e); 192.112(a), (b), (d), (e); 192.113; and Item I, Appendix B to Part 192.

(8) ANSI/API Specification 6D, "Specification for Pipeline Valves,"23rd edition, effective October 1, 2008, including Errata 1 (June 2008), Errata2 (/November 2008), Errata 3 (February 2009), Errata 4 (April 2010), Errata 5 (November 2010), Errata 6 (August 2011) Addendum 1 (October 2009), Addendum 2 (August 2011), and Addendum 3 (October 2012), (ANSI/API Spec 6D), IBR approved for §192.145(a).

(9) API Standard 1104, "Welding of Pipelines and Related Facilities," 20th edition, October 2005, including errata/addendum (July 2007) and errata 2 (2008), (API Std 1104), IBR approved for §§192.225(a); 192.227(a); 192.229(c); 192.241(c); and Item II, Appendix B.

(10) API Recommended Practice 1170, "Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage," First edition, July 2015 (API RP 1170), IBR approved for §192.12.

(11) API Recommended Practice 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs," First edition, September 2015, (API RP 1171), IBR approved for §192.12.

(12) API STANDARD 1163, "In-Line Inspection Systems Qualification," Second edition, April 2013, Reaffirmed August 2018, (API STD 1163), IBR approved for §192.493.

(c) ASME International (ASME), Three Park Avenue, New York, NY 10016, 800-843-2763 (U.S./Canada), *http://www.asme.org/.*

(1) ASME/ANSI B16.1-2005, "Gray Iron Pipe Flanges and Flanged Fittings: (Classes 25, 125, and 250)," August 31, 2006, (ASME/ANSI B16.1), IBR approved for §192.147(c).

(2) ASME/ANSI B16.5-2003, "Pipe Flanges and Flanged Fittings, "October 2004, (ASME/ANSI B16.5), IBR approved for §§192.147(a) and 192.279, and 192.607(f)

(3) ASME B16.40-2008, "Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems," March 18, 2008, approved by ANSI, (ASME B16.40-2008), IBR approved for Item I, Appendix B to Part 192.

(4) ASME/ANSI B31G-1991 (Reaffirmed 2004), "Manual for Determining the Remaining Strength of Corroded Pipelines," 2004, (ASME/ANSI B31G), IBR approved for §§192.485(c), 192.632(a), 192.712(b) and 192.933(a).

(5) ASME/ANSI B31.8-2007, "Gas Transmission and Distribution Piping Systems," November 30, 2007, (ASME/ANSI B31.8), IBR approved for §§192.112(b) and 192.619(a).

(6) ASME/ANSI B31.8S-2004, "Supplement to B31.8 on Managing System Integrity of Gas Pipelines," 2004, (ASME/ANSI B31.8S-2004), IBR approved for §§192.903 note to *Potential impact radius;* 192.907 introductory text, (b); 192.911 introductory text, (i), (k), (l), (m); 192.913(a), (b), (c); 192.917 (a), (b), (c), (d), (e); 192.921(a); 192.923(b); 192.925(b); 192.927(b), (c); 192.929(b); 192.933(c), (d); 192.935 (a), (b); 192.937(c); 192.939(a); and 192.945(a).

(7) ASME Boiler & Pressure Vessel Code, Section I, "Rules for Construction of Power Boilers 2007," 2007 edition, July 1, 2007, (ASME BPVC, Section I), IBR approved for §192.153(b).

(8) ASME Boiler & Pressure Vessel Code, Section VIII, Division 1 "Rules for Construction of Pressure Vessels," 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 1), IBR approved for §§192.153(a), (b), (d); and 192.165(b).

(9) ASME Boiler & Pressure Vessel Code, Section VIII, Division 2 "Alternate Rules, Rules for Construction of Pressure Vessels," 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 2), IBR approved for §§192.153(b), (d); and 192.165(b).

(10) ASME Boiler & Pressure Vessel Code, Section IX: "Qualification Standard for Welding and Brazing Procedures, Welders, Brazers, and Welding and Brazing Operators," 2007 edition, July 1, 2007, ASME BPVC, Section IX, IBR approved for §§192.225(a); 192.227(a); and Item II, Appendix B to Part 192.

(d) American Society for Nondestructive Testing (ANST), P.O. Box 28518, 1711 Arlington Lane, Columbus, OH 43228, phone: 800-222-2768, website: https://www.asnt.org/.

(1) ANSI/ASNT ILI-PQ-2005(2010), "In-line Inspection Personnel Qualification and Certification," Reapproved October 11, 2010 (ANSI/ASNT ILI-PQ), IBR approved for §192.493.

(2) [Reserved]

(e) American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, Web site: *http://www.astm.org/.*

(1) ASTM A53/A53M-10, "Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless," approved October 1, 2010, (ASTM A53/A53M), IBR approved for §192.113; and Item II, Appendix B to Part 192.

(2) ASTM A106/A106M-10, "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service," approved October 1, 2010, (ASTM A106/A106M), IBR approved for §192.113; and Item I, Appendix B to Part 192.

(3) ASTM A333/A333M-11, “Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service,” approved April 1, 2011, (ASTM A333/A333M), IBR approved for §192.113; and Item I, Appendix B to Part 192.

(4) ASTM A372/A372M-10, “Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels,” approved October 1, 2010, (ASTM A372/A372M), IBR approved for §192.177(b).

(5) ASTM A381-96 (reapproved 2005), “Standard Specification for Metal-Arc Welded Steel Pipe for Use with High-Pressure Transmission Systems,” approved October 1, 2005, (ASTM A381), IBR approved for §192.113; and Item I, Appendix B to Part 192.

(6) ASTM A578/A578M-96 (reapproved 2001), “Standard Specification for Straight-Beam Ultrasonic Examination of Plain and Clad Steel Plates for Special Applications,” (ASTM A578/A578M), IBR approved for §192.112(c).

(7) ASTM A671/A671M-10, “Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures,” approved April 1, 2010, (ASTM A671/A671M), IBR approved for §192.113; and Item I, Appendix B to Part 192.

(8) ASTM A672/A672M-09, “Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures,” approved October 1, 2009, (ASTM A672/672M), IBR approved for §192.113 and Item I, Appendix B to Part 192.

(9) ASTM A691/A691M-09, “Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures,” approved October 1, 2009, (ASTM A691/A691M), IBR approved for §192.113 and Item I, Appendix B to Part 192.

(10) ASTM D638-03, “Standard Test Method for Tensile Properties of Plastics,” 2003, (ASTM D638), IBR approved for §192.283(a) and (b).

(11) ASTM D2513-12ae1, “Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings,” April 1, 2012, (ASTM D2513-12ae1), IBR approved for Item I, Appendix B to Part 192.

(12) ASTM D2517-00, “Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings,” (ASTM D 2517), IBR approved for §§192.191(a); 192.281(d); 192.283(a); and Item I, Appendix B to Part 192.

(13) ASTM D2564-12, “Standard Specification for Solvent Cements for Poly (Vinyl Chloride) (PVC) Plastic Piping Systems,” Aug. 1, 2012, (ASTM D2564-12), IBR approved for §192.281(b)(2).

(14) ASTM F1055-98 (Reapproved 2006), "Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing," March 1, 2006, (ASTM F1055-98 (2006)), IBR approved for §192.283(a), Item I, Appendix B to Part 192.

(15) ASTM F1924-12, "Standard Specification for Plastic Mechanical Fittings for Use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing," April 1, 2012, (ASTM F1924-12), IBR approved for Item I, Appendix B to Part 192.

(16) ASTM F1948-12, "Standard Specification for Metallic Mechanical Fittings for Use on Outside Diameter Controlled Thermoplastic Gas Distribution Pipe and Tubing," April 1, 2012, (ASTM F1948-12), IBR approved for Item I, Appendix B to Part 192.

(17) ASTM F1973-13, "Standard Specification for Factory Assembled Anodeless Risers and Transition Fittings in Polyethylene (PE) and Polyamide 11 (PA11) and Polyamide 12 (PA12) Fuel Gas Distribution Systems," May 1, 2013, (ASTM F1973-13), IBR approved for §192.204(b); and Item I, Appendix B to Part 192.

(18) ASTM F2145-13, "Standard Specification for Polyamide 11 (PA 11) and Polyamide 12 (PA12) Mechanical Fittings for Use on Outside Diameter Controlled Polyamide 11 and Polyamide 12 Pipe and Tubing," May 1, 2013, (ASTM F2145-13), IBR approved for Item I, Appendix B to Part 192.

(19) ASTM F 2600-09, "Standard Specification for Electrofusion Type Polyamide-11 Fittings for Outside Diameter Controlled Polyamide-11 Pipe and Tubing," April 1, 2009, (ASTM F 2600-09), IBR approved for Item I, Appendix B to Part 192.

(20) ASTM F2620-12, "Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings," Aug. 1, 2012, (ASTM F2620-12), IBR approved for §§192.281(c) and 192.285(b)(2)(i).

(21) ASTM F2767-12, "Specification for Electrofusion Type Polyamide-12 Fittings for Outside Diameter Controlled Polyamide-12 Pipe and Tubing for Gas Distribution," Oct. 15, 2012, (ASTM F2767-12), IBR approved for Item I, Appendix B to Part 192.

(22) ASTM F2785-12, "Standard Specification for Polyamide 12 Gas Pressure Pipe, Tubing, and Fittings," Aug. 1, 2012, (ASTM F2785-12), IBR approved for Item I, Appendix B to Part 192.

(23) ASTM F2817-10, "Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair," Feb. 1, 2010, (ASTM F2817-10), IBR approved for Item I, Appendix B to Part 192.

(24) ASTM F2945-12a "Standard Specification for Polyamide 11 Gas Pressure Pipe, Tubing, and Fittings," Nov. 27, 2012, (ASTM F2945-12a), IBR approved for Item I, Appendix B to Part 192.

(f) Gas Technology Institute (GTI), formerly the Gas Research Institute (GRI)), 1700 S. Mount Prospect Road, Des Plaines, IL 60018, phone: 847-768-0500, Web site: *www.gastechnology.org.*

(1) GRI 02/0057 (2002) "Internal Corrosion Direct Assessment of Gas Transmission Pipelines Methodology," (GRI 02/0057), IBR approved for §192.927(c).

(2) [Reserved]

(g) Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park St. NE., Vienna, VA 22180, phone: 703-281-6613, Web site: *http://www.mss-hq.org/.*

(1) MSS SP-44-2010, Standard Practice, "Steel Pipeline Flanges," 2010 edition, (including Errata (May 20, 2011)), (MSS SP-44), IBR approved for §192.147(a).

(2) [Reserved]

(h) NACE International (NACE), 1440 South Creek Drive, Houston, TX 77084: phone: 281-228-6223 or 800-797-6223, Web site: *http://www.nace.org/Publications/.*

(1) ANSI/NACE SP0502-2010, Standard Practice, "Pipeline External Corrosion Direct Assessment Methodology," revised June 24, 2010, (NACE SP0502), IBR approved for §§192.923(b); 192.925(b); 192.931(d); 192.935(b) and 192.939(a).

(2) NACE Standard Practice 0102-2010, "In-line Inspection of Pipelines," Revised 2010-03-13 (NACE SP0102), IBR approved for §192.150(a) and 192.493.

(i) National Fire Protection Association (NFPA), 1 Batterymarch Park, Quincy, Massachusetts 02169, phone: 1 617 984-7275, Web site: *http://www.nfpa.org/.*

(1) NFPA-30 (2012), "Flammable and Combustible Liquids Code," 2012 edition, June 20, 2011, including Errata 30-12-1 (September 27, 2011) and Errata 30-12-2 (November 14, 2011), (NFPA-30), IBR approved for §192.735(b).

(2) NFPA-58 (2004), "Liquefied Petroleum Gas Code (LP-Gas Code)," (NFPA-58), IBR approved for §192.11(a), (b), and (c).

(3) NFPA-59 (2004), "Utility LP-Gas Plant Code," (NFPA-59), IBR approved for §192.11(a), (b); and (c).

(4) NFPA-70 (2011), "National Electrical Code," 2011 edition, issued August 5, 2010, (NFPA-70), IBR approved for §§192.163(e); and 192.189(c).

(j) Pipeline Research Council International, Inc. (PRCI), c/o Technical Toolboxes, 3801 Kirby Drive, Suite 520, P.O. Box 980550, Houston, TX 77098, phone: 713-630-0505, toll free: 866-866-6766, Web site: *http://www.ttoolboxes.com/.* (Contract number PR-3-805.)

(1) AGA, Pipeline Research Committee Project, PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe," (December 22, 1989), (PRCI PR-3-805 (R-STRENG)), IBR approved for §§192.485(c); 192.632(a); 192.712(b); 192.933(a) and (d).

(2) [Reserved]

(k) Plastics Pipe Institute, Inc. (PPI), 105 Decker Court, Suite 825 Irving TX 75062, phone: 469-499-1044, *http://www.plasticpipe.org/.*

(1) PPI TR-3/2012, HDB/HDS/PDB/SDB/MRS/CRS, Policies, "Policies and Procedures for Developing Hydrostatic Design Basis (HDB), Hydrostatic Design Stresses (HDS), Pressure Design Basis (PDB), Strength Design Basis (SDB), Minimum Required Strength (MRS) Ratings, and Categorized Required Strength (CRS) for Thermoplastic Piping Materials or Pipe," updated November 2012, (PPI TR-3/2012), IBR approved for §192.121.

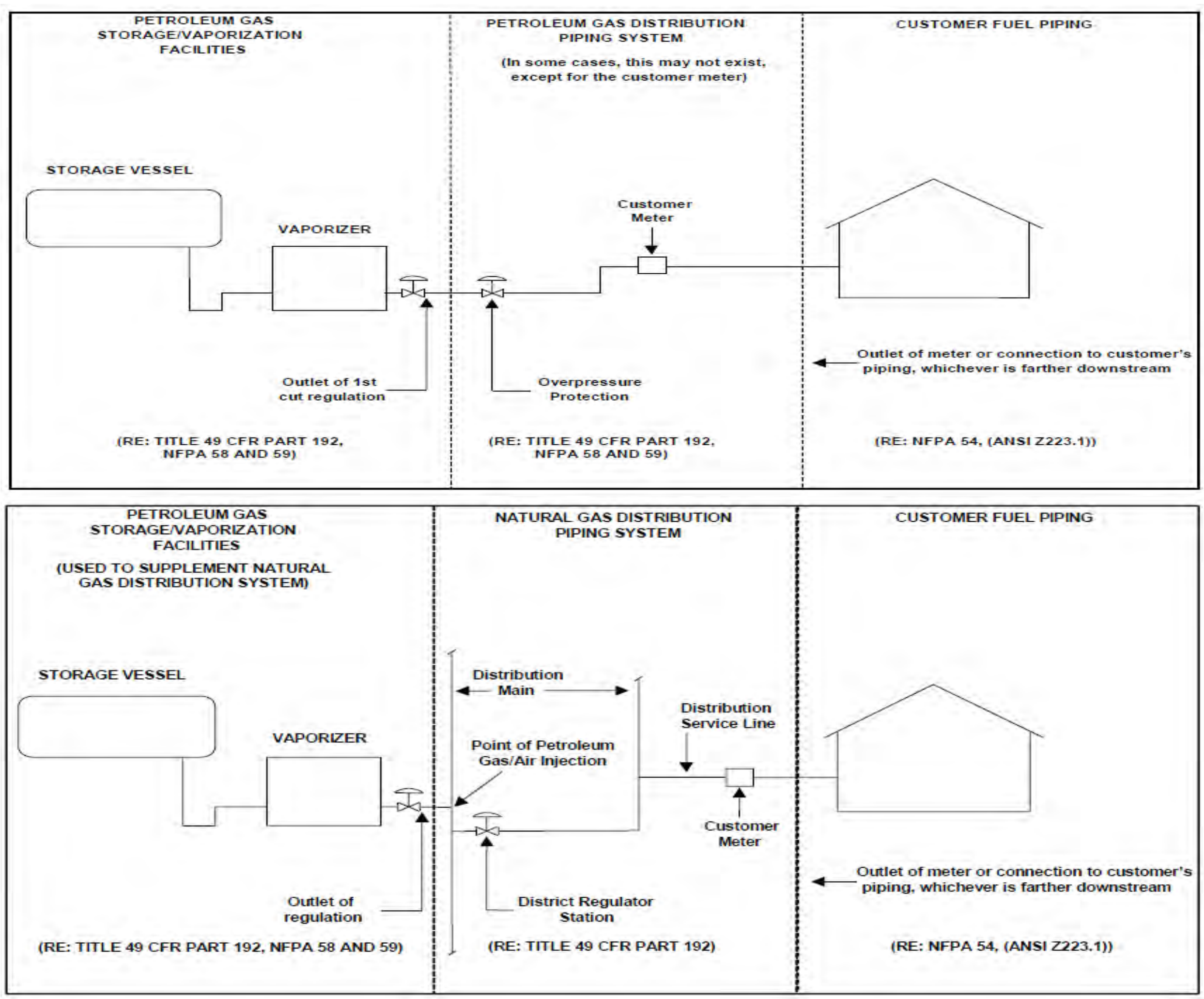
(2) PPI TR-4, HDB/HDS/SDB/MRS, Listed Materials, "PPI Listing of Hydrostatic Design Basis (HDB), Hydrostatic Design Stress (HDS), Strength Design Basis (SDB), Pressure Design Basis (PDB) and Minimum Required Strength (MRS) Rating For Thermoplastic Piping Materials or Pipe," updated March, 2011, (PPI TR-4/2012), IBR approved for §192.121.

Division 2.4: Propane Gas Systems & Propane Peak Shaving Plants

(Reference 192.11)

1) Each plant that supplies petroleum gas by pipeline to a natural gas distribution system must meet the requirements of 49 CFR Part 192 and NFPA 58 and NFPA 59.
2) Each pipeline system that transports only petroleum gas or a petroleum gas/air mixture must meet the requirements of 49 CFR Part 192 and of NFPA 58 and NFPA 59.
3) In the event of a conflict between 49 CFR Part 192 and NFPA 58 and NFPA 59, NFPA 58 and NFPA 59 prevail.

Examples of Propane Gas System &/or Propane Peak Shaving Plants:



(continued on next page)

General Information:

1. Personnel involved in the design, construction, operation, and maintenance of petroleum gas systems should be familiar with the applicable provisions of the Federal Regulations and reference NFPA Standards.

Application of Referenced Codes:

1. The referenced NFPA Standards are applicable unless otherwise superseded, in whole or in part, by local governmental agency codes, rules, or regulations having jurisdiction.
2. Plant and storage facilities include storage tanks and all piping and equipment to the outlet of the first pressure regulator. Utility plant facilities having a total water storage capacity greater than 4,000 gallons are covered b NFPA 59. All other plant and storage installations should comply with NFPA 58.

NOTE: The operators of petroleum gas distribution systems may benefit from information provided in the "Guidance Manual for Operators of LP Gas Systems" and "Operator Qualification Guidance Manual for Operators of LP Gas Systems" available at www.phmsa.dot.gov/training/pipeline/guidance-manuals.

Division 2.5: General Requirements for Regulated Pipelines

(Reference 192.13)

No person may operate a segment of pipeline listed in the first column of the chart below that is put into service after the date in in the second column of the chart below, unless:

1) The pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance to 49 CFR Part 192, or the pipeline qualifies for use under the requirements set in Division 2.6 of this Plan.

Pipeline	Date
Offshore gathering line	July 31, 1977
Regulated onshore gathering line to which 49 CFR Part 192 did not apply until April 14, 2006.	March 15, 2007
All other pipelines	March 12, 1971

2) No person may operate a segment of pipeline listed in the first column of the chart below that is replaced, relocated, or otherwise changes after the date in the second column of the chart below, unless the replacement, relocation or change has been made according to the requirements in this Plan.

Pipeline	Date
Offshore gathering line	July 31, 1977
Regulated onshore gathering line to which 49 CFR Part 192 did not apply until April 14, 2006.	March 15, 2007
All other pipelines	November 12, 1970

3) Each operator shall maintain, modify as appropriate, and follow the plans, procedures, and programs that are required by 49 CFR Part 192 and this O&M Plan.

Division 2.6: Pipeline Conversion into Service *(Reference 192.14)*

NOTE: All pipelines that were in service but not subject to the requirements of 49 CFR Part 192 may **NOT** be converted for use according to this Plan. A new pipeline system must be installed according to the requirements found in this Plan to ensure the safety of customers and the integrity of the pipeline system. If an operator determines that it is in their best interest to convert a pipeline already in service, the operator must develop procedures according to the requirements below.

A steel pipeline previously in service but not subject to 49 CFR Part 192 qualifies for use according to 49 CFR Part 192 if the operator prepares and follows a written procedure to carry out the following requirements:

1) The design, construction, operation, and maintenance history of the pipeline must be reviewed and, where sufficient historical records are not available, appropriate tests must be performed to determine if the pipeline is in a satisfactory condition for safe operation.
2) The pipeline right-of-way, all aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline.
3) All known unsafe defects and conditions must be corrected in accordance with 49 CFR Part 192.
4) The pipeline must be tested in accordance with 49 CFR Part 192 Subpart J to substantiate the MAOP permitted by 49 CFR Part 192 Subpart L.

Each operator must keep for the life of the pipeline a record of the investigations, tests, repairs, replacements, and alterations made under the requirements of paragraph (1) of this section.

Division 2.7: Customer Owned Piping Notification *(Reference 192.16)*

1. Division Definitions:

- *Customer Owned Piping* – Buried piping that is **NOT** owned or maintained by the gas company. This may include any buried piping located downstream of the meter that serve one or more buildings, structures, or gas burning appliances located on the same property.
- *Maintain* – Means to monitor for corrosion, if the piping is metallic, according to Division 10 of this Plan, conduct leak surveys according to Division 14 of this Plan, and if an unsafe condition is found, shut off the flow of gas, advise the customer of the need to repair the unsafe condition, or repair the unsafe the condition.

2. Notification Requirements:

Each operator who does **NOT** maintain customer owned piping, according to the definition above, must notify each customer once in writing of their responsibility to maintain their own piping. This written notice must be distributed to the customer within 90 days of when the customer signs up for service. The written notice must contain the following information:

1) That the operator does **NOT** maintain customer owned piping.
2) If the customer owned piping is not maintained, it may be subject to the potential hazards of corrosion and leakage.
3) The buried gas piping should be,
    a) Periodically inspected for leaks
    b) Periodically inspected for corrosion if the piping is metallic
    c) Repaired if any unsafe condition is discovered.
4) Before excavating, One-Call must be notified and all utilities marked. When excavating within 18 inches of a buried gas line, excavation should be done by hand, being careful not to damage the buried pipe.
5) Plumbing contractors, heating contractors, or the operator (if applicable), can assist in locating, inspecting, and repairing the customer's buried piping.

NOTE #1: Although not required, the operator may choose to periodically readvise customers of their responsibility to maintain their own piping. This may be completed by using bill stuffers, posting the notice on your company website and directing customers to view it, newsletters, adding the notice to your Public Awareness informational materials, etc.

NOTE #2: An example of a Customer Owned Piping Notification can be found on the next page.

(continued on next page)

Below is an example of a customer owned piping notification that is available to be downloaded from the Iowa Association of Municipal Utilities website at www.iamu.org.

Customer Owned Piping Notification

As your natural gas distributor, CITY OF BLOOMFIELD, IOWA Municipal Utilities, in accordance with federal regulations, wishes to make you aware of certain safety recommendations regarding your underground natural gas piping.

CITY OF BLOOMFIELD, IOWA Municipal Utilities operates our gas system with an emphasis on safety. We are required to design, operate and maintain our underground natural gas pipeline in accordance with prescribed federal safety standards. The gas system does not maintain the gas piping that is customer owned. Customer owned piping is any piping that is located after the utility owned gas meter. These lines feeding a structure or a gas burning appliance are the responsibility of the customer who owns that piping. If the buried pipe is not properly maintained, it may be subject to corrosion (if the piping is metallic) and/or leakage. To ensure the continued safe and reliable operation of these lines, the buried piping should be periodically inspected for corrosion and checked for leaks. If any unsafe condition is discovered at any time, repairs should be made as soon as possible.

Before any excavation, One-Call must be notified and all utilities marked. When excavating within 18 inches of a buried gas line, excavation should be done by hand, being careful not to damage the buried pipe. You (or the building owner) are advised to contract a licensed plumber or heating contractor or possibly the gas operator to assist you in locating, inspecting and repairing your buried gas piping.

If we can answer any questions regarding this notice, please give us a call at 641-664-9652.

Sincerely: TODD SCHUMAKER

Title: GAS SUPERINTENDENT

Division 2.7.1: Customer Owned Piping Notification; Record Requirements

(Reference 192.16)

Each operator must make the following records available for inspection by PHMSA or the State agency responsible for pipeline safety and inspection.

a) The most current copy of the customer owned piping notification that is being distributed.
b) A record must be kept of those customers who received the notice for the previous 3 years. The record must also provide proof that the notice was delivered within 90 days of the customer first receiving service.

Division 2.8: How to Notify PHMSA *(Reference 192.18)*

1) An operator must provide any notification required by this Division to PHMSA by the following means:
   a) Sending the notification by email to InformationResourcesManager@dot.gov or;
   b) Sending the notification by mail to: ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd Floor, E22-321, 1200 New Jersey Ave. SE, Washington DC 20590.
2) An operator must also notify the appropriate State or local pipeline safety authority (Iowa Utilities Board) when an applicable pipeline segment is located in a State where OPS has an interstate agreement, or an intrastate applicable pipeline segment is regulated by that State.
3) Unless otherwise specified, if the notification is made pursuant to § 192.506(b), § 192.607(e)(4), § 192.607(e)(5), § 192.624(c)(2)(iii), § 192.624(c)(6), § 192.632(b)(3), § 192.710(c)(7), § 192.712(d)(3)(iv), § 192.712(e)(2)(i)(E), § 192.921(a)(7), or § 192.937(c)(7) to use a different integrity assessment method, analytical method, sampling approach, or technique (*i.e.,* "other technology") that differs from that prescribed in those sections, the operator must notify PHMSA at least 90 days in advance of using the other technology. An operator may proceed to use the other technology 91 days after submittal of the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing the operator that PHMSA objects to the proposed use of other technology or that PHMSA requires additional time to conduct its review.

CITY OF BLOOMFIELD, IOWA

DIVISION THREE

Materials

49 CFR Part 192 Subpart B

Division 3.1: General Information *(Reference 192.53)*

Materials used for pipe and components must be:

1) Able to maintain the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated.
2) Chemically compatible with any gas that they transport and with any other material in the pipeline with which they are in contact with.
3) Qualified in accordance with the applicable requirements of 49 CFR Part 192 Subpart B and this Plan.

Division 3.2: Steel Pipe Requirements *(Reference 192.55)*

1. New Steel Pipe:

New steel pipe is qualified for service in pipelines if:

1) It was manufactured in accordance with a listed specification (listed specifications can be found in Appendix B of this Plan).
2) It meets the requirements of section II of Appendix B of this Plan.
3) If it was manufactured before November 12, 1970, either section II or III of Appendix B of this Plan.
4) It is used in accordance with paragraph 1) or 2) of the "Additional Requirements" subsection listed below.

2. Used Steel Pipe:

Used steel pipe is qualified for service in pipelines if:

1) It was manufactured in accordance with a listed specification found in section I of Appendix B and it meets the requirements of paragraph II-C or Appendix B.
2) It meets the requirements of section II of Appendix B or if it was manufactured before November 12, 1970, either section II or III of Appendix B.
3) It has been used in an existing line of the same or higher pressure and meets the requirements of paragraph II-C of Appendix B.

3. Additional Requirements:

1) New or used steel pipe may be used at a pressure resulting in a hoop stress of less than 6,000 psi where no close coiling or close bending is to be done, if visual examination indicates that the pipe is in good condition and that it is free of split seams and other defects that would cause leakage. If it is to be welded, steel pipe that has not been manufactured to a listed specification must also pass the weldability tests prescribed in 49 CFR 192, Appendix B, Paragraph II (B).
2) Steel pipe that has not been previously used may be used as replacement pipe in a segment of pipeline if it has been manufactured prior to November 12, 1970, in accordance with the same specification as the pipe used in constructing that segment of pipeline.
3) New steel pipe that has been cold expanded must comply with the mandatory provisions of API Specification 5L.

NOTE: Appendix B listed above can be found on the next 4 pages of this Division of this Plan.

Appendix B - Qualification of Pipe and Components

I. List of Specifications

A. Listed Pipe Specifications

API Spec 5L - Steel pipe, "API Specification for Line Pipe" (incorporated by reference, *see*§ 192.7).
ASTM A53/A53M - Steel pipe, "Standard Specification for Pipe, Steel Black and Hot-Dipped, Zinc-Coated, Welded and Seamless" (incorporated by reference, *see*§ 192.7).
ASTM A106/A-106M - Steel pipe, "Standard Specification for Seamless Carbon Steel Pipe for High Temperature Service" (incorporated by reference, *see*§ 192.7).
ASTM A333/A333M - Steel pipe, "Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service" (incorporated by reference, *see*§ 192.7).
ASTM A381 - Steel pipe, "Standard Specification for Metal-Arc-Welded Steel Pipe for Use with High-Pressure Transmission Systems" (incorporated by reference, *see*§ 192.7).
ASTM A671/A671M - Steel pipe, "Standard Specification for Electric-Fusion-Welded Pipe for Atmospheric and Lower Temperatures" (incorporated by reference, *see*§ 192.7).
ASTM A672/A672M-09 - Steel pipe, "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures" (incorporated by reference, *see*§ 192.7).
ASTM A691/A691M-09 - Steel pipe, "Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High Pressure Service at High Temperatures" (incorporated by reference, *see*§ 192.7).
ASTM D2513-12ae1"Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings" (incorporated by reference, see § 192.7).
ASTM D 2517-00 - Thermosetting plastic pipe and tubing, "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (incorporated by reference, *see*§ 192.7).
ASTM F2785-12 "Standard Specification for Polyamide 12 Gas Pressure Pipe, Tubing, and Fittings" (PA-12) (incorporated by reference, *see*§ 192.7).
ASTM F2817-10 "Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair" (incorporated by reference, *see*§ 192.7).
ASTM F2945-12a "Standard Specification for Polyamide 11 Gas Pressure Pipe, Tubing, and Fittings" (PA-11) (incorporated by reference, *see*§ 192.7).

B. Other Listed Specifications for Components

ASME B16.40-2008 "Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems" (incorporated by reference, *see*§ 192.7).
ASTM D2513-12ae1"Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings" (incorporated by reference, see § 192.7).
ASTM D 2517-00 - Thermosetting plastic pipe and tubing, "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (incorporated by reference, *see*§ 192.7).
ASTM F2785-12 "Standard Specification for Polyamide 12 Gas Pressure Pipe, Tubing, and Fittings" (PA-12) (incorporated by reference, *see*§ 192.7).
ASTM F2945-12a "Standard Specification for Polyamide 11 Gas Pressure Pipe, Tubing, and Fittings" (PA-11) (incorporated by reference, *see*§ 192.7).

ASTM F1055-98 (2006) “Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing” (incorporated by reference, *see*§ 192.7).
ASTM F1924-12 “Standard Specification for Plastic Mechanical Fittings for Use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing” (incorporated by reference, *see*§ 192.7).
ASTM F1948-12 “Standard Specification for Metallic Mechanical Fittings for Use on Outside Diameter Controlled Thermoplastic Gas Distribution Pipe and Tubing” (incorporated by reference, *see*§ 192.7).
ASTM F1973-13 “Standard Specification for Factory Assembled Anodeless Risers and Transition Fittings in Polyethylene (PE) and Polyamide 11 (PA 11) and Polyamide 12 (PA 12) Fuel Gas Distribution Systems” (incorporated by reference, *see*§ 192.7).
ASTM F 2600-09 “Standard Specification for Electrofusion Type Polyamide-11 Fittings for Outside Diameter Controlled Polyamide-11 Pipe and Tubing” (incorporated by reference, *see*§ 192.7).
ASTM F2145-13 “Standard Specification for Polyamide 11 (PA 11) and Polyamide 12 (PA12) Mechanical Fittings for Use on Outside Diameter Controlled Polyamide 11 and Polyamide 12 Pipe and Tubing” (incorporated by reference, *see*§ 192.7).
ASTM F2767-12 “Specification for Electrofusion Type Polyamide-12 Fittings for Outside Diameter Controlled Polyamide-12 Pipe and Tubing for Gas Distribution” (incorporated by reference, *see*§ 192.7).
ASTM F2817-10 “Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair” (incorporated by reference, *see*§ 192.7).

II. Steel Pipe of Unknown or Unlisted Specification.

A. *Bending Properties.* For pipe 2 inches (51 millimeters) or less in diameter, a length of pipe must be cold bent through at least 90 degrees around a cylindrical mandrel that has a diameter 12 times the diameter of the pipe, without developing cracks at any portion and without opening the longitudinal weld.

For pipe more than 2 inches (51 millimeters) in diameter, the pipe must meet the requirements of the flattening tests set forth in ASTM A53/A53M (incorporated by reference, *see*§ 192.7), except that the number of tests must be at least equal to the minimum required in paragraph II-D of this appendix to determine yield strength.

B. *Weldability.* A girth weld must be made in the pipe by a welder who is qualified under subpart E of this part. The weld must be made under the most severe conditions under which welding will be allowed in the field and by means of the same procedure that will be used in the field. On pipe more than 4 inches (102 millimeters) in diameter, at least one test weld must be made for each 100 lengths of pipe. On pipe 4 inches (102 millimeters) or less in diameter, at least one test weld must be made for each 400 lengths of pipe. The weld must be tested in accordance with API Standard 1104 (incorporated by reference, *see*§ 192.7). If the requirements of API Standard 1104 cannot be met, weldability may be established by making chemical tests for carbon and manganese, and proceeding in accordance with section IX of the ASME Boiler and Pressure Vessel Code (ibr, *see* 192.7). The same number of chemical tests must be made as are required for testing a girth weld.

C. *Inspection.* The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and there are no defects which might impair the strength or tightness of the pipe.

D. *Tensile Properties.* If the tensile properties of the pipe are not known, the minimum yield strength may be taken as 24,000 p.s.i. (165 MPa) or less, or the tensile properties may be established by performing tensile tests as set forth in API Specification 5L (incorporated by reference, *see*§ 192.7). All test specimens shall be selected at random and the following number of tests must be performed:

NUMBER OF TENSILE TESTS - ALL SIZES

10 lengths or less	1 set of tests for each length.
11 to 100 lengths	1 set of tests for each 5 lengths, but not less than 10 tests.
Over 100 lengths	1 set of tests for each 10 lengths, but not less than 20 tests.

If the yield-tensile ratio, based on the properties determined by those tests, exceeds 0.85, the pipe may be used only as provided in § 192.55(c).

III. *Steel pipe manufactured before November 12, 1970, to earlier editions of listed specifications.*

Steel pipe manufactured before November 12, 1970, in accordance with a specification of which a later edition is listed in section I of this appendix, is qualified for use under this part if the following requirements are met:

A. *Inspection.* The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and that there are no defects which might impair the strength or tightness of the pipe.

B. *Similarity of specification requirements.* The edition of the listed specification under which the pipe was manufactured must have substantially the same requirements with respect to the following properties as a later edition of that specification listed in section I of this appendix:

(1) Physical (mechanical) properties of pipe, including yield and tensile strength, elongation, and yield to tensile ratio, and testing requirements to verify those properties.

(2) Chemical properties of pipe and testing requirements to verify those properties.

C. *Inspection or test of welded pipe.* On pipe with welded seams, one of the following requirements must be met:

(1) The edition of the listed specification to which the pipe was manufactured must have substantially the same requirements with respect to nondestructive inspection of welded seams and the standards for acceptance or rejection and repair as a later edition of the specification listed in section I of this appendix.

(2) The pipe must be tested in accordance with subpart J of this part to at least 1.25 times the maximum allowable operating pressure if it is to be installed in a class 1 location and to at least 1.5 times the maximum allowable operating pressure if it is to be installed in a class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under subpart J of this part, the test pressure must be maintained for at least 8 hours.

[35 FR 13257, Aug. 19, 1970]

EDITORIAL NOTE:
For Federal Register citations affecting appendix B to part 192, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at *www.govinfo.gov.*

Division 3.3: Plastic Pipe Requirements *(Reference 192.59)*

1. New Plastic Pipe

New plastic pipe is qualified for service in pipelines if:

1) It is manufactured in accordance with a listed specification found in section I of Appendix B of this Plan.
2) Resistant to chemicals with which contact may be anticipated.
3) Free of visible defects

2. Used Plastic Pipe

Used plastic pipe is qualified for service in pipelines if:

1) It was manufactured in accordance with a listed specification found in section I of Appendix B of this Plan.
2) Resistant to chemicals with which contact may be anticipated.
3) It has only been used in natural gas service.
4) Its dimensions are still within the tolerances of the specification to which it was manufactured.
5) Free of visible defects.

3. Additional Requirements

1) Must meets the strength and design criteria required of pipe included in the that listed specification.
2) Is manufactured from plastic compounds which meet the criteria for material required of pipe included in that listed specification.
3) Rework and/or regrind material is not allowed in plastic pipe produced after March 6, 2015.

NOTE: Appendix B listed above can be found on pages 52 – 55 of this section of this Plan.

4. Weathering of Plastic Pipe

1) The integrity of plastic pipe can be affected greatly by storing outdoors and subject to UV light. Refer to Division of 3.7 of this Plan for specific procedures and storage requirements for plastic pipe.

Division 3.4: Marking of Materials *(Reference 192.63)*

1) Each valve, fitting, length of pipe, and other component must be marked as prescribed in the specification or standard to which it was manufactured (with the exception of (4) & (5) shown below).
2) Surfaces of pipe and components that are subject to stress from internal pressure may NOT be field die stamped.
3) If any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations.
4) Paragraph (1) of this section does **NOT** apply to items manufactured before November 12, 1970, that meet all of the following:
    a) The item is identifiable as to type, manufacturer, and model.
    b) Specifications or standards giving pressure, temperature, and other appropriate criteria for the use of items are readily available.
5) All plastic pipe and components must also meet the following requirements:
    a) All markings on plastic pipe prescribed in ASTM D2513-18a(7) and the requirements of paragraph (c) found below must be repeated at intervals not exceeding two feet.
    b) Plastic pipe and components manufactured after December 31, 2019 must be marked in accordance with ASTM D2513-18a(7).
    c) All physical markings on plastic pipelines required by this section, must be legible until the time of installation.

NOTE: See the next two pages for an example of pipe markings and a brief description of those markings.

(Continued on next page)

1" IPS – Pipe Size and/or Sizing System

- Iron Pipe Size (IPS) – The pipe has the same outside diameter as iron pipe of the same nominal size.
- Copper Tube Size (CTS) – The pipe has the same outside diameter as copper tubing of the same nominal size.

DR11 – Standard Dimension Ratio

- This indicates the dimension ratio or wall thickness of the pipe.

Driscoplex – Manufacturer or Product Name

- All manufactured pipe will have the name of the manufacturer or product name stamped into the pipe wall.

6500 – Series Number

- This may or may not be included on the pipe depending on the manufacturer and pipe type.

Gas – End Use Application

- This indicates the type of product that the pipe was intended for.

PE2708 – Pipe Material Designation Code

- The letters "PE" in the pipe designation code represent polyethylene.
- PE 2406/2708 represent medium density pipe and PE 3408/4710 represent high density pipe.
- The first two numbers represent the type and grade of pipe and the last two numbers represent the hydrostatic design base.

CEE – Pipe Category Code

- C – indicates the temperature of the pressure rating of the pipe.
- E – represents the hydrostatic design basis (HDB) at the highest recommended temperature.

(continued on next page)

ASTM D2513 – Manufacturing Standard

- The manufacturing stand with which the pipe complies (such as ASTM D2513) must be printed on the pipe.

KVXXX – Lot Number

- The Lot Number consists of the manufacturing plant code and the resin code.
- The first two letter represent the manufacturing plant code
  - FF=Fairfield, IA
  - PR=Pryor, OK
  - RN=Reno, NV
  - WT=Williamstown, NJ
  - KV=Knoxville, TN

NR – No Rework

- This indicates that the plastic used for manufacturing has not been ground or pelletized and reused by the manufacturer.

cNSFusGas – Third Party Compliance

- Third party compliance will vary depending on the listing requested from the manufacturer.

480 – Sequential Footage Counter

- This will indicate the distance in feet from the beginning of the pipe.

04JAN12 – Date of Manufacture

- This may be printed in various formats, but will include the day, month and year the pipe was manufactured.

Division 3.5: Transportation of Pipe *(Reference 192.65)*

1. Transportation by Railroad

1) In a pipeline to be operated at a hoop stress of 20% or more of SMYS, an operator may NOT install pipe having an outer diameter to wall thickness of 70 to 1, or more, that is transported by railroad unless the transportation is performed by API RP 5L1.

2. Transportation by Truck

1) In a pipeline to be operated at a hoop stress of 20% or more of SMYS, an operator may NOT install pipe having an outer diameter to wall thickness of 70 to 1, or more, that is transported by truck unless the transportation is performed by API RP 5LT.

Division 3.6: Records for Material Properties (Transmission) *(Reference 192.67)*

1. Transmission Pipeline Installed After July 1, 2020

For steel transmission pipelines installed after July 1, 2020, an operator must collect or make, and retain for the life of the pipeline documents that contain the following information:

a) Pipeline physical characteristics
   i) Diameter
   ii) Yield strength
   iii) Ultimate tensile strength
   iv) Wall thickness
   v) Seam type
b) Chemical composition of materials in pipe according to Division 3.1 and 3.2 of this Plan.
c) Records must include test, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed.

2. Transmission Pipeline Installed on or Before July 1, 2020

1) If operators **DO HAVE** records that document tests, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition in accordance with Division 3.1 and 3.2 of this Plan, operators must retain those records for the life of the pipeline.
2) If an operator **DOES NOT HAVE** records necessary to establish the MAOP of pipeline segment, the operator may be subject to the requirements of Division 13.15 of this Plan.

Division 3.7: Storage and Handling of Plastic Pipe and Components

(Reference 192.69)

Each operator must have and follow written procedures for the storage and handling of plastic pipe and components that meet the applicable listed standard.

1. Requirements for Storage of Pipe

1) Before installing plastic pipe and fittings that have been stored outdoors, the manufacturing date must be checked prior to installation to ensure that the outdoor storage limitations have not been exceeded. The outdoor storage limitations of plastic pipe have been determined for this Plan according to ASTM D2513-12ae1 (incorporated by reference in Division 2.3). The operator should consider requiring a written statement from the manufacturer or sales representative as to how long the pipe has been stored outdoors without UV protection.

    - Unprotected outdoor storage for yellow or black plastic pipe shall not exceed 2 years or the manufacturers recommendations, whichever is less.

2) If installing plastic pipe and fittings with a manufacture date that exceeds the limits listed above, the operator must provide documented proof of indoor or covered storage limiting the pipe and/or fittings exposure to UV light.
3) When storing pipe either indoors or outdoors, the storage surface should have a relatively smooth, level surface free of stones, debris or other foreign materials that could damage the pipe or fittings.
4) If adequate ground conditions do not exist, the pipe may be placed on planking. The planking should be padded and evenly spaced with the bottom layer of pipe far enough above the ground surface to prevent water, dirt and debris from entering open ends of the pipe.
5) If possible, coils of plastic pipe should lie flat when stored.
6) If storage of the pipe on a rack is required, store small pipe according to length and size. Block or strap the pipe to prevent it from rolling or falling off of the rack. Pipe larger than 2" in diameter should be stacked with spacing strips between each row.
7) When pipes of variable wall thickness are received, it is recommended that the pipe be separated into piles, with each pile containing a single pipe size and pressure rating to minimize using the incorrect pipe at a later date. If stacking, the thickest walled pipe should always be stored at the bottom and the pile should be constructed in a pyramidal manner, with each layer having one less pipe section than the layer below. The bottom layer should be braced to prevent movement or rolling of the pile.

2. Requirements for Handling of Pipe

1) Delivery Inspection
   a) The load must be inspected for evidence of shifting during transportation, along with any damage that may have occurred during loading, transportation, or previous handling.
   b) If any damage is found during inspection, the supplier/shipper and the carrier should be notified immediately upon receipt of the shipment. Pipe and/or fittings should be repaired or replaced as necessary to maintain quality control and quality assurance.
2) Loading and Unloading
   a) If using equipment with forks, the forks should be inspected for jagged edges or burrs. If the forks are marred, a suitable means of covering the forks should be used to prevent gouging of the pipe or fitting. Always lift from the center of the pipe while using the forks in their widest position possible.
   b) If using equipment without forks, a fabric sling or nylon rope should be used to prevent damage to the pipe or fitting.
   c) If possible, coils of pipe should be transported and stored with the coil laid flat.
3) Before and During Installation
   a) Care should be taken while handling plastic pipe and fitting during installation to ensure that damage is not sustained by the pipe or fitting.
   b) A visual inspection of the pipe and fitting surface must be completed before installation.
      i) If scratches, gouges, defects, or imperfections are found during visual inspection, a pit gauge, penetrometer, or some other type of measurement device should be used to determine the depth of the scratch, gouge, defect or imperfection.
      ii) If more than 10% of the pipe or fitting wall has been removed due to the scratch, gouge, defect, or imperfection, that pipe section or fitting must be repaired or replaced before installation of the pipe or fitting can occur.

CITY OF BLOOMFIELD, IOWA

DIVISION FOUR

Pipe Design

49 CFR Part 192 Subpart C

Division 4.1: General Information *(Reference 192.101 & 192.103)*

All pipe used must be designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipe after installation. Consideration should also be given to stresses associated with transportation, handling during construction, geotechnical forces, and secondary loads that may occur during construction, operation, or maintenance. Considerations should also be given to welding or mechanical joining requirements for the installation of the pipe.

Division 4.2: Design Formula for Steel Pipe *(Reference 192.105)*

1. The design pressure for steel pipe is determined according to the following formula:

$$P = (2\ St/D) \times F \times E \times T$$

P = Design pressure in pounds per square inch (kPa) gauge.

S = Yield strength in pounds per square inch (kPa) which is determined according to CFR Part 192.107 (Division 4.2.1 of this Plan).

D = Nominal outside diameter of the pipe in inches.

t = Nominal wall thickness of the pipe in inches. If this is unknown, it is determined according to CFR Part 192.109 (Division 4.2.2 of this Plan).

F = Design factor determined according to CFR Part 192.111 (Division 4.2.3 of this Plan).

E = Longitudinal joint factor determined according to CFR Part 192.113 (Division 4.2.4 of this Plan).

T = Temperature derating factor determined according to CFR Part 192.115 (Division 4.2.5 of this Plan).

2. If steel pipe that has been subjected to cold expansion to meet the SMYS is subsequently heated, other than by welding or stress relieving as a part of welding, the design pressure is limited to 75% of the pressure determined under paragraph (1) of this Division if the temperature of the pipe exceeds 900°F at any time or is held above 600°F for more than one hour.

NOTE: A nominal outside diameter table is provided on the next page to calculate for (D) in the design formula.

(continued on next page)

The chart below provides the nominal outside diameter (D) used in the design formula for nominal pipe sizes (NPS) 12 and less. For pipe sizes greater than NPS 12, the nominal pipe size and the nominal outside diameter are the same.

PIPE SIZE AND OUTSIDE DIAMETER [1,2]			
Nominal Pipe Size (NPS)	**Nominal Outside Diameter (*D*) (Inches)**	**Nominal Pipe Size (NPS)**	**Nominal Outside Diameter (*D*) (Inches)**
⅛	0.405	2½	2.875
¼	0.540	3	3.500
⅜	0.675	3½	4.000
½	0.840	4	4.500
¾	1.050	5	5.563
1	1.315	6	6.625
1¼	1.660	8	8.625
1½	1.900	10	10.750
2	2.375	12	12.750

[1] Values obtained from ASTM A53 for steel pipe and from ASTM D2513 for plastic pipe.

[2] This table applies to steel, plastic, and some types of cast iron pipe.

Division 4.2.1: Yield Strength (S) for Steel Pipe *(Reference 192.107)*

1. For pipe that is manufactured according to a specification listed in Section 1 of Appendix B of this Plan, the yield strength to be used in the design formula (Division 4.2) is the SMYS stated in the listed specification, if that value is known.

2. For pipe that is manufactured according to a specification that is **NOT** listed in Section 1 of Appendix B of this Plan or whose specification or tensile properties are unknown, the yield strength to be used in the design formula (Division 4.2) is one of the following:

   a) If the pipe is tensile tested according to Section II-D of Appendix B of this Plan, the lower of the following.
      i) 80% of the average yield strength determined by the tensile test.
      ii) The lowest yield strength determined by the tensile test.
   b) If the pipe is not tensile tested as provided in paragraph 2(a) of this Division, 24,000 psi is to be used in the design formula.

Division 4.2.2: Nominal Wall Thickness (t) for Steel Pipe *(Reference 192.109)*

1. If the nominal wall thickness for steel pipe is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end.

2. However, if the pipe is of uniform grade, size, and thickness and there are more than 10 lengths, only 10% of the individual lengths, but not less than 10 lengths, need be measured. The thickness of the lengths that are not measured must be verified by applying a gauge set to the minimum thickness found by the measurement. The nominal wall thickness to be used in the design formula found in Division 4.2 of this Plan, is the next wall thickness found in commercial specification that is below the average of all the measurements taken. However, the nominal wall thickness used may not be more than 1.14 times the smallest measurement taken on pipe less than 20 inches in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe 20 inches or more in outside diameter.

Division 4.2.3: Design Factor (F) for Steel Pipe *(Reference 192.111)*

1) Except for paragraphs 2), 3), and 4) of this Division, the design factor to be used in the design formula found in Division 4.2 of this Plan is determined according to the following table:

Class Location	Design Factor (F)
1	0.72
2	0.60
3	0.50
4	0.40

2) A design factor of 0.60 or less must be used in the design formulas in Division 4.2 of this Plan for steel pipe in Class 1 locations that:
   a) Crosses the right-of-way of an unimproved public road, without a casing;
   b) Crosses with a casing, or makes a parallel encroachment on, the right-of-way of either a hard-surfaced road, a highway, a public street, or a railroad;
   c) Is supported by a vehicular, pedestrian, railroad, or pipeline bridge; or
   d) Is used in a fabricated assembly, (including separator, mainline valve assemblies, cross-connections, and river crossing headers) or is used within five pipe diameters in any direction from the last fitting of a fabricated assembly, other than a transition piece or an elbow used in place of a pipe bend which is not associated with a fabricated assembly.
3) For Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in Division 4.3 of this Plan for uncased steel pipe that crosses the right-of-way of a hard-surfaced road, a highway, a public street, or a railroad.
4) For Class 1 and 2 locations, a design factor of 0.50, or less, must be used in the design formula in Division 4.3 of this Plan for the following:
   a) Steel pipe in a compressor station, regulating station, or measuring station, and
   b) Steel pipe, including a pipe riser, on a platform located offshore or in a inland navigable waters.

Division 4.2.4: Longitudinal Joint Factor (E) for Steel Pipe *(Reference 192.113)*

1) The longitudinal joint factor to be used in the design formula found in Division 4.2 of this Plan is determined according to the following table:

Specification	Pipe Class	Longitudinal Joint Factor (E)
ASTM A 53/A53M	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded	0.60
ASTM A 106	Seamless	1.00
ASTM A 333/ A 333M	Seamless	1.00
	Electric resistance welded	1.00
ASTM A 381	Double submerged arc welded	1.00
ASTM A 671	Electric-fusion-welded	1.00
ASTM A 672	Electric-fusion-welded	1.00
ASTM A 691	Electric-fusion-welded	1.00
API Spec 5L	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
	Furnace butt welded	0.60
Other	Pipe over 4 inches	0.80
Other	Pipe 4 inches or less	0.60

2) If the type of longitudinal joint cannot be determined, the joint factor to be used must not exceed that as designated in the “Other” column listed in the table above.

Division 4.2.5: Temperature Derating Factor (T) for Steel Pipe *(Reference 192.113)*

1) The temperature derating factor to be used in the design formula found in Division 4.2 of this Plan is determined according to the following table:

Gas Temperature in Degrees Fahrenheit	Temperature Derating Factor (T)
250°F	1.000
300°F	0.967
350°F	0.933
400°F	0.900
450°F	0.867

2) For intermediate gas temperatures, the derating factor is determined by interpolation.

Division 4.2.6: Additional Design Requirements for Steel Pipe Using Alternative Maximum Allowable Operating Pressure *(Reference 192.112)*

For a new or existing pipeline segment to be eligible for operation at the alternative maximum allowable operating pressure (MAOP) calculated according to 49 CFR Part 192.620 (NOT included in this Plan), a segment must meet the additional design requirements. Records for alternative MAOP must be maintained for the useful life of the pipeline in order to demonstrate compliance with the requirements:

NOTE: See the table found in 49 CFR Part 192.112 for the specific additional design requirements of the rule.

Division 4.3: Design of Plastic Pipe *(Reference 192.121)*

Subject to the limitations found in Division 4.3.1 of this Plan, the design pressure for plastic pipe is determined by the either of the following formulas:

$$P = 2S\frac{t}{(D-t)}(DF)$$

$$P = \frac{2S}{(SDR-1)}(DF)$$

P = Design pressure, gauge, psig (kPa).
S = For thermoplastic pipe, the hydrostatic design basis (HDB) is determined in accordance with the listed specification at a temperature equal to 73°F, 100°F, 120°F, or 140°F. In the absence of an HDB established at the specified temperature, the HDB of a higher temperature may be used in determining a design pressure rating at the specified temperature by arithmetic interpolation using the procedure in Part D.2 of PPI TR-3/2012 (incorporated by reference). For reinforced thermosetting plastic pipe, 11,000 psig shall be used.
t = Specified wall thickness, inches
D = Specified outside diameter, inches
SDR = Standard dimension ratio, the ratio of the average specified outside diameter to the minimum specified wall thickness, corresponding to a value from a common numbering system that was derived from the American National Standards Institute (ANSI) preferred number series 10.
DF = Design Factor, a maximum of 0.32 for polyethylene (PE) or 0.40 for polyamide (PA-11) pipe produced after January 23, 2009 with a nominal pipe size (IPS or CTS) 4 inch or less, and a SDR of 11 or greater.

NOTE: See the next 4 pages for specific requirements for polyethylene and polyamide piping materials.

Division 4.3.1: General Requirements for Plastic Pipe and Components

(Reference 192.121)

1) Except as provided in subsection 1 through 4 of this Division, the design pressure of plastic pipe may not exceed a gauge pressure of 100 psig for pipe used in the following:
    a) Distribution systems
    b) Class 3 or 4 transmission lines.
2) Plastic pipe may not be used where operating temperatures of the pipe will be:
    a) Below -20°F, or below -40°F if all pipe and pipeline components whose operating temperature will be below -20°F have a temperature rating by the manufacturer consistent with that operating temperature, or
    b) Above the temperature at which the HDB used in the design formula found in Division 4.3 of this Plan is determined.
3) Unless specified for a particular material found in this Division, the wall thickness of plastic pipe may not be less than 0.062 inches
4) All plastic pipe must have a listed HDB in accordance with PPI TR-4/2012

1. Polyethylene (PE) Pipe Requirements

1) For PE pipe produced after July 14, 2004, but before January 22, 2019, a design pressure of up to 125 psig may be used, if:
    a) The material designation code is PE2406 or PE3408
    b) The pipe has a nominal size (IPS or CTS) of 12 inches or less.
    c) If the pipe has a nominal size greater than 12 inches, the design pressure is limited to 100 psig.
    d) Wall thickness of the pipe must not be less than 0.062 inches.
2) For PE pipe produced after January 22, 2019, a design factor of 0.40 may be used in the design formula found in Division 4.3 of this Plan, if:
    a) The design pressure does not exceed 125 psig.
    b) The material designation code is PE2708 or PE4710
    c) The pipe has a nominal size less than or equal to 12 inches.
    d) Wall thickness for a given outside diameter is not less than what is listed in the table below.

Pipe Size (inches)	Minimum Wall Thickness (inches)	SDR Value
½” CTS	0.090	7
¾” CTS	0.090	9.7
½” IPS	0.090	9.3

NOTE: *Table is continued at the top of the next page.*

NOTE: Table continued from previous page.

Pipe Size (inches)	Minimum Wall Thickness (inches)	SDR Value
¾” IPS	0.095	11
1” CTS	0.119	11
1” IPS	0.119	11
1 ¼” IPS	0.151	11
1 ½” IPS	0.173	11
2”	0.216	11
3”	0.259	13.5
4”	0.265	17
6”	0.315	21
8”	0.411	21
10”	0.512	21
12”	0.607	21

2. Polyamide (PA-11) Pipe Requirements

1) For PA-11 pipe produced after January 23, 2009, but before January 22, 2019 a design factor of 0.40 may be used in the design formula found in Division 4.3 of this Plan, if:
   a) The design pressure does not exceed 200 psig.
   b) The material designation code is PA32312 or PA32316.
   c) The nominal size of the pipe (IPS or CTS) is 4 inches or less.
   d) The pipe has an SDR of 11 or less (thicker wall pipe).
2) For PA-11 pipe produced after January 22, 2019, a design factor of 0.40 may be used in the design formula found in Division 4.3 of this Plan, if:
   a) The design pressure does not exceed 250 psig.
   b) The material designation code is PA32316.
   c) The nominal size of the pipe (IPS or CTS) is 6 inches or less.
   d) Minimum wall thickness for a given outside diameter is not less than what is listed in the table below.

Pipe Size (inches)	Minimum Wall Thickness (inches)	SDR Value
½” CTS	0.090	7
¾” CTS	0.090	9.7
½” IPS	0.090	9.3
¾” IPS	0.095	11
1” CTS	0.119	11
1” IPS	0.119	11
1 ¼” IPS	0.151	11

NOTE: Table is continued at the top of the next page.

NOTE: Table continued from previous page.

Pipe Size (inches)	Minimum Wall Thickness (inches)	SDR Value
1 ½” IPS	0.173	11
2” IPS	0.216	11
3” IPS	0.259	13.5
4” IPS	0.333	13.5
6” IPS	.0491	13.5

3. Polyamide (PA-12) Pipe Requirements

1) For PA-12 pipe produced after January 22, 2019, a design factor of 0.40 may be used in the design formula found in Division 4.3 of this Plan, if:
   a) The design pressure does not exceed 250 psig.
   b) The material designation code is PA42316.
   c) The nominal size of the pipe (IPS or CTS) is 6 inches or less.
   d) The minimum wall thickness for a given outside diameter is not less than what is listed in the table below.

Pipe Size (inches)	Minimum Wall Thickness (inches)	SDR Value
½” CTS	0.090	7
¾” CTS	0.090	9.7
½” IPS	0.090	9.3
¾” IPS	0.095	11
1” CTS	0.119	11
1” IPS	0.119	11
1 ¼” IPS	0.151	11
1 ½” IPS	0.173	11
2” IPS	0.216	11
3” IPS	0.259	13.5
4” IPS	0.333	13.5
6” IPS	.0491	13.5

(continued on next page)

4. Reinforced Thermosetting Plastic Pipe Requirements

1) Reinforced thermosetting plastic pipe may not be used at an operating temperature above 150°F.
2) The wall thickness for reinforced thermosetting plastic pipe may not be less than what is listed in the table below.

Pipe Size (inches)	Minimum Wall Thickness (inches)
2"	0.060
3"	0.060
4"	0.070
6"	0.100

Division 4.4: Design of Copper Pipe *(Reference 192.125)*

1) The use of copper pipe for mains is **NOT** allowed according to this Plan.
2) Copper pipe used for service lines must have a wall thickness not less than what is shown in the table below.

Standard size inch (millimeter)	Nominal O.D. inch (millimeter)	Wall thickness inch (millimeter)	
		Nominal	Tolerance
½ (13)	.625 (16)	.040 (1.06)	.0035 (.0889)
⅝ (16)	.750 (19)	.042 (1.07)	.0035 (.0889)
¾ (19)	.875 (22)	.045 (1.14)	.004 (.102)
1 (25)	1.125 (29)	.050 (1.27)	.004 (.102)
1¼ (32)	1.375 (35)	.055 (1.40)	.0045 (.1143)
1½ (38)	1.625 (41)	.060 (1.52)	.0045 (.1143)

3) Copper pipe used in service lines must not exceed pressures in excess of 100 psig.
4) Copper pipe that does not have an internal corrosion resistant lining may not be used to carry gas that has an average hydrogen sulfide content of more than 0.3 grains/100ft^3 under standard conditions. Standard conditions refer to 60°F and 14.7 psia of gas.

Division 4.5: Pipe Design Records (Transmission) *(Reference 192.127)*

1. Transmission Pipelines Installed After July 1, 2020

1) An operator must collect or make, and retain for the life of the pipeline, records documenting that the pipe is designed to withstand anticipated external pressures and loads in accordance with Division 4.1 of this Plan and documenting that the determination of design pressure for the pipe is made in accordance with Division 4.2 of this Plan.

2. Transmission Pipelines Installed on or Before July 1, 2020

1) If operators **DO HAVE** records documenting pipe design and the determination of design pressure in accordance with Division 4.1 & 4.2 of this Plan, those records must be retained for the life of the pipeline.
2) If operator DO NOT HAVE records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of Division 13.15 of this Plan.

CITY OF BLOOMFIELD, IOWA

DIVISION FIVE

Design of Pipeline Components

49 CFR Part 192 Subpart D

Division 5.1: Scope *(Reference 192.141)*

This Division details the minimum requirements for the design and installation of pipeline components and facilities. It also details the requirements for the protection of facilities against accidental over-pressuring.

Division 5.2: General Requirements *(Reference 192.143)*

1) Each component of a pipeline must be able to withstand operating pressures and other anticipated loadings without impairing its serviceability with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service. However, if design based upon unit stresses is impractical for a particular component, design may be based upon a pressure rating established by the manufacturer by pressure testing that component or a prototype of the component.
2) The design and installation of pipeline components and facilities must meet applicable requirements for corrosion control found in Division 10 of this Plan.
3) Except for excess flow valves, each plastic pipeline component installed after January 22, 2019 must be able to withstand operating pressures and other anticipated loads in accordance with a listed specification.

Division 5.3: Qualifying Metallic Components *(Reference 192.144)*

Notwithstanding any requirement of this Division which incorporates by reference an edition of a document listed in Division 2.3 or Appendix B of this Plan, a metallic component manufactured in accordance with any other edition of that document is qualified for use according to this Plan if:

1) It can be shown through visual inspection of the cleaned component that no defect exists which might impair the strength or tightness of the component; and
2) The edition of the document under which the component was manufactured has equal or more stringent requirements for the following as an edition of that document currently or previously listed in Division 2.3 or Appendix B of this Plan:
    a) Pressure testing;
    b) Materials; and
    c) Pressure and temperature ratings.

Division 5.4: Valves *(Reference 192.145)*

1) Except for cast iron and plastic valves, each valve must meet the requirements of ANSI/API Spec 6D (incorporated by reference, see Division 2.3), or to a national or international standard that provides an equivalent performance level. A valve may **NOT** be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those requirements.
2) Valve standards API Spec 6A, API Std 600, ASME B16.34, and ASME B16.38 provide an equivalent performance level to API Spec 6D for gas application purposes.
3) Although all valve sizes (those smaller than 2") are not listed in API Spec 6D, manufacturers may design, build, and test non-listed sized in accordance with all applicable requirements of API Spec 6D, thereby meeting the equivalency criteria.
4) All cast iron and plastic valves must comply with the following:
   a) The valve must have a maximum service pressure rating for temperatures that equal or exceed the maximum service temperature.
   b) The valve must be tested as part of the manufacturing, as follows:
      i) With the valve in the fully open position, the shell must be tested with no leakage to a pressure at least 1.5 times the maximum service rating.
      ii) After the shell test, the seat must be tested to a pressure not less than 1.5 times the maximum service pressure rating. Except for swing check valves, test pressure during the seat test must be applied successively on each side of the closed valve with the opposite side open. No visible leakage is permitted.
      iii) After the last pressure test is completed, the valve must be operated through its full travel to demonstrate freedom from interference.
5) Each valve must be able to meet the anticipated operating conditions.
6) No valve having shell (body, bonnet, cover, and/or end flange) components made of ductile iron may be used at pressures exceeding 80% of the pressure ratings for comparable steel valves at their listed temperature. However, a valve having shell components made of ductile iron may be used at pressures up to 80% of the pressure ratings for comparable steel valves at their listed temperature, if:
   a) The temperature-adjusted service pressure does not exceed 1,000 psi gage; and
   b) Welding is not used on any ductile iron component in the fabrication of the valve shells or their assembly.
5) No valve having shell (body, bonnet, cover, and/or end flange) components made of cast iron, malleable iron, or ductile iron may be used in the gas pipe components of compressor stations.
6) Except for excess flow valves, plastic valves installed after January 22, 2019, must meet the minimum requirements of ASME B16.40. A valve may not be used under operating conditions that exceed the applicable pressure and temperature ratings contained in the listed specification.

Division 5.5: Flange and Flange Accessories *(Reference 192.147)*

NOTE: See IAMU Procedure #1.12: Joining of Pipe – Flange Assembly for installation procedures.

1) Each flange or flange accessory (other than cast iron) must meet the minimum requirements of ASME/ANSI B16.5 and MSS SP-44 (incorporated by reference, see Division 2.3) or the equivalent.
2) Each flange assembly must be able to withstand the maximum pressure at which the pipeline is to be operated and to maintain its physical and chemical properties at any temperature to which it is anticipated that it might be subjected in service.
3) Each flange on a flanged joint in cast iron pipe must conform in dimensions, drilling, face and gasket design to ASME/ANSI B16.1 (incorporated by reference, see Division 2.3) and be cast integrally with the pipe, valve, or fitting.

1. Flange Types

1) All line or end flanges should conform to one of the following standards.
   a) ASME B16.1, ASME B16.5, ASME B16.36, ASME B16.47, ASME B16.48, AWWA C207, or MSS SP-44.
2) Threaded companion flanges that comply with either ASME B16.1 or ASME B16.5 may be used.
3) Lapped flanges in sizes and pressure standards established by ASME 16.5 are allowed.
4) Slip-on welding flanges in sizes and pressure standards established in ASME B16.5 may be used. Slip-on flanges of rectangular section may be substituted for hubbed slip-on flanges provided the thickness is increased as required to produce equivalent strength as determined by calculations made in accordance with Section VIII, Pressure Vessels, of the ASME Boiler & Pressure Vessel Code.
5) Welding neck flanges in sizes and pressure standards established in ASME B16.5, ASME B16.47, and MSS SP-44 may be used. The bore of the flanges should correspond to the inside diameter of the pipe used.
6) Flanges made of ductile iron should conform to material and dimensional standards listed in API Spec 6D or the equivalent and should be subject to all service restrictions as outlined for valves found in Division 5.4 of this Plan.

2. Flange Facings

1. Cast iron, ductile iron, and steel flanges should have contact faces finished in accordance with MSS SP-6.
2. Class 25 & Class 125 cast iron integral or threaded companion flanges may be used with a full face or flat ring gasket extending to the inner edge of the bolt holes. When using a full faced gasket, the bolting may be of alloy steel (ASTM A193). When using a flat ring gasket, the bolting should be of carbon steel equivalent to ASTM A307 Grade B.

(Continued on next page)

3. When bolting together two Class 250 flanges, having 1/16" raised faces, the bolting should be of carbon steel equivalent to ASTM A307 Grade B.
4. Class 150 steel flanges may be bolted to a Class 125 cast iron flange as long as the 1/16" raised face on the steel flange is removed. When using a flat ring gasket, bolting should be of carbon steel equivalent to ASTM A307 Grade B. When using a full-face gasket, the bolting may be alloy steel (ASTM A193).
5. Class 300 steel flanges may be bolted to Class 250 cast iron flanges as long as the bolting is completed using carbon steel equivalent to ASTM A307 Grade B. It is also recommended that raised face on the steel flange be removed prior to installation.
6. Forged steel welding neck flanges that comply with ASME B16.1, but with modified flange thicknesses, hub dimensions, and special facing details, may be used to bolt against flat-faced cast iron flanges, and may operate at the pressure/temperature rating given in ASME B16.1 Class 125 Cast Iron Pipe Flanges given the following:
   a) The minimum flange thickness, *T*, of the steel flange is not less than that specified for size 6" and larger
   b) Flanges are used with nonmetallic full-face gaskets extending to the outer edge of the flange.
   c) The design joint has been proven by test to be suitable for the ratings.

3. Flange Gaskets

1) Gasket material should be capable of withstanding the maximum pressures and temperatures to which it might reasonably be subjected to during service.
2) Gaskets used at temperatures above 250°F should be made of noncombustible materials.
3) Metallic gaskets should not be used with Class 150 or lower rated flanges.

4. Flange Insulation Kits

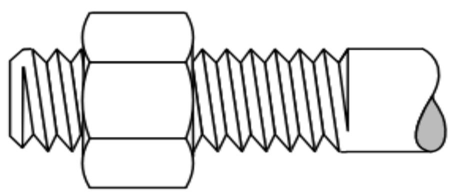
1) Insulating kits provide electrical isolation at flanged connections. Insulating kits typically contain a gasket, washer, and sleeves for the bolts. The insulating kits to be used should be compatible with the gas stream and the external environment to which it will be subjected.

(Continued on next page)

5. Flange Bolts

1) Except for requirements described in Subpart 2, of this Division, all flange bolts should be made of alloy steel conforming to ASTM A193, A320 or A354, or of heat-treated carbon steel conforming to ASTM A449. However, bolting used for American National Standard Class 250 and 300 flanges to be used at temperatures between -20°F and 450°F may be made to ASTM A307, Grade B.
2) For insulating flanges where bolts are 1/8” undersized, alloy steel bolts conforming to ASTM A193 or ASTM A354 should be used.
3) The materials used for nuts should conform to ASTM A194 and ASTM A307. ASTM A307 nuts may only be used with ASTM A307 bolts.
4) Bolts should have American National Standard regular square heads or heavy hexagonal heads and should have American National Standard Heavy hexagonal nuts conforming to the dimensions of ASME B18.2.1 and B18.2.2.
5) For all flange joints, the bolts or stud bolts used should extend completely through the nuts. This means that the first two tapered threads of the bolt should extend completely through the nut. See diagram below.

Diagram of correct installation



Division 5.6: Standard Fittings *(Reference 192.149)*

1) The minimum metal thickness of threaded fittings may not be less than specified for the pressures and temperatures in the applicable standards referenced in Division 2.3 of this Plan, or their equivalent.
2) Each steel butt-welding fitting must have pressure and temperature ratings based on stresses for pipe of the same or equivalent material. The actual bursting strength of the fitting must at least equal the computed bursting strength of pipe of the designated material and wall thickness, as determined by a prototype that was tested to at least the pressure required for the pipeline to which it is being added.
3) Plastic fittings installed after January 22, 2019, must meet a listed specification.

Division 5.7: Passage of Internal Inspection Devices *(Reference 192.150)*

1) Except for paragraph 2) and 3) of this Division, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must be designed and constructed to accommodate the passage of internal inspection devices in accordance with NACESP0102, section 7.
2) The guidelines laid out in this Division **DO NOT** apply to the following:
   a) Manifolds
   b) Station piping such as at compressor stations, meter stations, or regulator stations
   c) Piping associated with storage facilities, other than a continuous run of transmission line between a compressor station and storage facilities
   d) Cross-overs
   e) Sizes of pipe for which an instrumented internal inspection device is not commercially available.
   f) Transmission lines, operated in conjunction with a distribution system which are installed in Class 4 locations
   g) Offshore transmission lines, except transmission lines 10 ¾ inches or more in outside diameter on which construction begins after December 28, 2005, that run from platform or platform to shore unless -
      i) Platform space or configuration is incompatible with launching or retrieving instrumented internal inspection devices;
      ii) If the design includes taps for lateral connections, the operator can demonstrate, based on investigation or experience, that there is no reasonably practical alternative under the design circumstances to the use of a tap that will obstruct the passage of instrumented internal inspection devices; and
   h) Other piping that under 49 CFR Part 190.9, the Administrator finds in a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices.
3) An operator encountering emergencies, construction time constraints or other unforeseen construction problems need not construct a new or replacement segment of a transmission line to meet paragraph 1) of this section, if the operator determines and documents why an impracticability prohibits compliance with paragraph 1) of this section. Within 30 days after discovering the emergency or construction problem the operator must petition, under §190.9 of this chapter, for approval that design and construction to accommodate passage of instrumented internal inspection devices would be impracticable. If the petition is denied, within 1 year after the date of the notice of the denial, the operator must modify that segment to allow passage of instrumented internal inspection devices.

Division 5.8: Tapping *(Reference 192.151)*

Each tap made on a pipeline under pressure must be performed by a crew that is qualified to make hot taps, using the manufactures' hot tap procedures. The following criteria apply to tapping.

1) At a minimum, each mechanical fitting used to make a hot tap, must be designed for the operating pressure of the pipeline to which it is attached.
2) If ductile iron pipe is being tapped, the extent of full-thread engagement and the need for the use of outside-sealing service connections, tapping saddles, or other fixtures must be determined by the service conditions.
3) If a threaded tap is made in cast iron or ductile iron pipe, the diameter of the tapped hole may NOT be more than 25% of the nominal diameter of the pipe unless the pipe is reinforced, unless the following conditions apply;
   a) Existing taps may be used for replacement service, if they are free of cracks and have good threads; and
   b) A 1 ¼ inch tap may be made in a 4-inch cast iron or ductile iron pipe without reinforcement. However, in areas where the climate, soil and service conditions create unusual external stresses on cast iron pipe, unreinforced taps may be used ONLY on 6-inch or larger pipe.

Additional Information

1) Procedures for steel and PE tapping can be found in Part 7: Pipeline Tapping and Stopping, of the O&M Written Procedures.
2) All procedures for preventing accidental ignition must also be followed while performing hot tapping operations. See IAMU Procedure #8.15 – Prevent Accidental Ignition for specific procedures.

Division 5.9: Components Fabricated by Welding & Welded Branch Connections *(Reference 192.153)*

1) Except for branch connections and assemblies of standard pipe and fittings joined by welds made around the circumference of the pipe or fitting, the design pressure of each component fabricated by welding, whose strength can't be determined, must be established in accordance with paragraph UG-101 of section VIII of the ASME Boiler and Pressure Vessel Code.
2) Each prefabricated unit that uses plate and longitudinal seams must be designated, constructed, and tested in accordance with the ASME Boiler and Pressure Vessel Code, except for the following:
   i) Regularly manufactured butt-welding fittings.
   ii) Pipe that has been produced and tested under a specification listed in Appendix B to this part of 49 CFR Part 192.
   iii) Partial assemblies such as split rings or collars.
   iv) Prefabricated units that the manufacturer certifies have been tested to at least twice the maximum pressure to which they will be subjected under the anticipated operating conditions.
3) Orange-peel bull plugs and orange-peel swages may not be used on pipelines that are to operate at a hoop stress of 20% or more of the SMYS of the pipe.
4) Except for flat closures designed in accordance with section VIII of the ASME Boiler and Pressure Code, flat closures and fish tails may not be used on pipe that either operates at 100 psi or more, or is more than 3 inches nominal diameter.

   NOTE: A component having a design pressure established in paragraph 1) or 2) of this Division and is to operate at 30% or more of SMYS, must be pressure tested to at least 1.5 times MAOP.

5) Each welded branch connection made to pipe in the form of a single connection, or in a header or manifold as a series of connections, must be designed to ensure that the strength of the pipeline system is not reduced, taking into account the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening, and any external loading due to thermal movement, weight and vibration.

Division 5.10: Extruded Outlets *(Reference 192.157)*

Each extruded outlet must be suitable for anticipated service conditions and must at least equal to the design strength of the pipe and other fittings to which it is attached.

Division 5.11: Pipeline Flexibility *(Reference 192.159)*

Each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stresses in the pipe or components, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.

1. Steel Pipe

1) The following chart provides expansion and contraction rates for steel pipe.

THERMAL EXPANSION OF CARBON AND LOW-ALLOY, HIGH-TENSILE STEEL AND WROUGHT-IRON PIPING

Temperature Degree F	Total expansion in inches per 100 feet above 32 °F
32	0.0
60	0.2
100	0.5
125	0.7
150	0.9
175	1.1
200	1.3
225	1.5
250	1.7
300	2.2
350	2.6
400	3.0
450	3.5

2) Formal calculations for expansion and contraction are only required where reasonable doubt exists to the adequate flexibility of the system.
3) Flexibility should be provided by the use of bends, loops, offsets, or provision should be made to absorb thermal changes by the use of expansion joints or couplings of the slip joint type. If expansion joints are used, anchors or ties of sufficient strength and rigidity should be installed to provide for end forces.
4) If calculations for flexibility are required, the system should be treated as a whole.

(Continued on next page)

2. Plastic Pipe

1) The following chart provides expansion and contraction rates for plastic pipe.

COEFFICIENTS OF THERMAL EXPANSION		
Pipe Material	Nominal Coefficients of Thermal Expansion [1] (x 10^{-5} in./in.)/(°F)	Expansion (in./100 ft. pipe)/(°F increase)
PA 32312 (PA 11)	9.0	0.108
PE 2406/PE 2708	9.0	0.108
PE 3408/PE 4710	9.0	0.108
PVC 1120	3.0	0.036
PVC 2116	4.0	0.048

[1] Individual compounds may differ from the values in this table by as much as ±10%. More exact values for specific commercial products may be obtained from the manufacturer.

PA = polyamide

PE = polyethylene

PVC = poly (vinyl chloride)

NOTE: PE pipe can either expand or contract at a rate of 1 inch per 100 feet of pipe when the temperature changes by 10°F.

2) When plastic piping is installed, it must be installed with sufficient slack to provide for possible contraction. Under high temperature conditions, cooling may be necessary before the final tie-in connection is made.
3) When possible (direct burial installations) the pipe should be installed by snaking the pipe in the ditch (pipe is relaxed with no tension).
4) If inserting PE pipe, push the pipe into place so that it is under compression rather than tension when making the final tie-in joint. ASTM D2513 Category 1 fittings should be used to provide additional protection against pull-out forces due to thermal changes.
5) Allowing for the effect of thermal expansion and contraction of installed pipe due to seasonal changes in temperature may be accomplished by any of the following;
   a) Offsets
   b) Anchoring or strapping the joint
   c) Expansion &/or contraction devices
   d) Full pull-out resistant fittings (ASTM D2513 Category 1)
   e) Any combination of the above

Division 5.12: Pipeline Supports and Anchors *(Reference 192.161)*

1) Each pipeline and its associated equipment must have enough anchors or supports to:
   a) Prevent undue strain on connected equipment;
   b) Resist longitudinal forces caused by a bend or off set in the pipe; and
   c) Prevent or damp out excessive vibration.
2) Each exposed pipeline must have enough supports or anchors to protect the exposed pipe joints from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipe and its contents.
3) Each support or anchor on an exposed pipeline must be made of durable, non-combustible material and must be designed and installed as follows:
   a) Free expansion and contraction of the pipeline between supports or anchors may not be restricted.
   b) Provision must be made for the service conditions involved.
   c) Movement of the pipeline may not cause disengagement of the support equipment.
4) Each support on an exposed pipeline operated at a stress level of 50% or more of SMYS must comply with the following:
   a) A structural support may not be welded directly to the pipe.
   b) The support must be provided by a member that completely encircles the pipe.
   c) If an encircling member is welded to a pipe, the weld must be continuous and cover the entire circumference.
5) Each underground pipeline that is connected to a relatively unyielding line or other fixed object must have enough flexibility to provide for possible movement, or it must have an anchor that will limit the movement of the pipeline.
6) Except for offshore pipelines, each underground pipeline that is being connected to new branches must have a firm foundation for both the header and the branch to prevent detrimental lateral and vertical movement.

Compression or Sleeve-type Couplings

Compression or sleeve-type couplings used in exposed piping should be designed and installed so that the joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping. If such provision is not made in the manufacture of the coupling, suitable bracing or strapping should be provided, but such design should not interfere with the normal performance or maintenance of the coupling.

Welding Supports or Anchors to Pipe

Structural supports or anchors may be welded directly to the pipe that is designed to operate at a hoop stress of less than 50% of SMYS. If the pipe is designed to operate at 50% or more of SMYS, structural supports or anchors may NOT be welded directly to the pipe.

Longitudinal Pullout Forces

Buried pipe joints that are close to the points of thrust origin should be designed to sustain the longitudinal force. The proper Category 1 joint, suitable bracing or strappings should be used.

Division 5.13: Pipe-Type & Bottle-Type Holders *(Reference 192.175 & 192.177)*

1) Each pipe-type and bottle-type holder must be designed so as to prevent the accumulation of liquids in the holder, in connecting pipe, or in auxiliary equipment, that might cause corrosion or interfere with the safe operation of the holder.
2) Each pipe-type or bottle-type holder must have minimum clearance from other holder in accordance with the following formula:

$$C = \frac{3D * P * F}{1000} \text{ in inches} \qquad \left(C = \frac{3D * P * F}{6{,}895} \right) \text{ in millimeters}$$

C = Minimum clearance between pipe containers or bottles in inches
D = Outside diameter of pipe container or bottles in inches
P = Maximum allowable operating pressure (MAOP)
F = Design factor as described in Division 4.2.3 of this Plan.

Additional Provisions

1) Each bottle-type holder must meet the following;
   a) Located on a site entirely surrounded by fencing that prevents unauthorized access with minimum clearances as described below.

Maximum allowable operating pressure	Minimum clearance feet (meters)
Less than 1,000 p.s.i. (7 MPa) gage	25 (7.6)
1,000 p.s.i. (7 MPa) gage or more	100 (31)

   b) Designed using the design factors found in Division 4.2.3 of this Plan.
   c) Buried with a minimum cover as found in Division 8.12 of this Plan.
2) Each bottle-type holder manufactured from steel that is not weldable under field conditions must comply with the following:
   a) A bottle-type holder made from alloy steel must meet the chemical and tensile requirements for the various grades of steel in ASTM A372/372M.
   b) The actual yield-tensile ratio of the steel may not exceed 0.85.
   c) Welding may not be performed on the holder after it has been heat treated or stress relieved, except that copper wires may be attached to the small diameter portion of the bottle end closure for cathodic protection if a localized thermite welding process is used.
   d) The holder must be given a mill hydrostatic test at a pressure that produces a hoop stress at least equal to 85% of SMYS.
   e) The holder, connection pipe, and components must be leak tested after installation according to Part Five – Pressure Testing of the O&M Written Procedures.

Division 5.14: Transmission Line Valves *(Reference 192.179)*

Each transmission line must have emergency valves installed according to the distances described in the table below:

Class 4 Location: Any point on the pipeline must be within 2 ½ miles of a valve
Class 3 Location: Any point on the pipeline must be within 4 miles of a valve
Class 2 Location: Any point on the pipeline must be within 7 ½ miles of a valve
Class 1 Location: Any point on the pipeline must be within 10 miles of a valve

1) Each transmission line valve and operating device must be readily accessible and protected from tampering or damage.
2) The valve must be supported to prevent settling of the valve or movement of the pipe to which it is attached.

Transmission Blowdown Valves - Location

1) Each section of transmission line, must have a blowdown valve installed between main line valves with enough capacity to allow the transmission line to be blown down as rapidly as practicable.
2) Each blowdown discharge must be located so the gas can be blown to the atmosphere without hazard.
3) Discharges should be located or directed sufficient distance away from overhead electric lines so that the gas is directed away from the electrical conductors.
4) Discharges should be located a sufficient distance away from buildings such that:
   a) Should vented gas ignite, buildings will not be in danger of ignition or heat damage.
   b) Noise emissions from blowdowns will have minimal impact on the public.

Transmission Blowdown Valves – Sizing

1) The operator should minimize blowdown time by properly sizing blowdown valves to:
   a) Reduce the time gas is venting through a pipeline rupture/damage and is susceptible to ignition.
   b) Reduce the duration of a gas fire, minimizing the impact on life and property.

Division 5.15: Distribution Line Valves *(Reference 192.181)*

1) Each high-pressure distribution system (any system that DOES NOT serve customers with mainline pressure) must have valves spaced so as to reduce the time to shut down a section of main in an emergency. The valve spacing is determined by the operating pressure, the size of the mains, and the local physical conditions.
2) Each regulator station controlling the follow or pressure of gas in a distribution system must have a valve installed on the inlet piping at a distance from the regulator station sufficient to permit the operation of the valve during an emergency that might prevent access to the station.
   NOTE: This is also known as a remote valve or fire valve.
3) Each valve installed on a main for the purpose of operating during an emergency must comply with the following conditions:
   a) The valve must be placed in a readily accessible location so that it may be easily found and operated during an emergency.
   b) The operating stem or mechanism of the valve must be readily accessible.
   c) If the valve is installed in a valve box or enclosure, the box or enclosure must not transmit loads onto the main pipe.

<u>Considerations for the Location of Distribution Line Valves:</u>

1) Size of area to be isolated?
2) Topographic features, such as rivers, major highways and railroads.
3) How many valves are needed to isolate a specific area?
4) Is the section a loop feed or single feed?
5) Total number of customers that could possibly be affected.
6) Is a school, church, hospital, commercial or industrial area going to be in the affected area?
7) How much time would be required for gas crews to perform isolation procedures in the event of a pipeline rupture?
8) Time and personnel that would be required to restore service in an outage?

Division 5.16: Vaults – Design, Accessibility, Sealing, Venting, Drainage & Waterproofing *(Reference 192.183, 192.185, 192.187, 192.189)*

1. Design

1) Each underground vault or pit designed for valves, pressure regulating, limiting, or relieving, must be able to withstand the external loads and protect the equipment installed within.
2) The vault or pit must have enough working space so that all of the equipment required can be properly installed, operated, and maintained.
3) Each pipe entering, or within, a regulator vault or pit must be steel of sizes 10" and less, except that control and gage piping may be copper. Where piping extends through the vault or pit structure, provisions must be made to prevent the passage of gasses or liquids through the opening and not produce any strain on the pipe.

<u>Supports</u>

i. Equipment and piping vaults or pits should be suitably supported by metal, masonry, or concrete supports.
ii. Control piping should be placed and supported so that the possibility of damage is reduced to a minimum within that specific installation.

<u>Openings</u>

i. Vault or pit openings should be located to minimize the possibility of tools or other objects falling on the regulator, control lines or other equipment.
ii. Control line piping should not be located under an opening unless it is protected from workers stepping on them.

2. Vault Accessibility

Each vault must be located in an accessible location and if practical, away from the following:

1) Street intersections or points where traffic is heavy or dense.
2) Points of minimum elevation, catch basins, or places where the access cover will be in course of surface waters.
3) Water, electric, steam, fiber optic, or other utility facilities.

3. Sealing, Venting, & Ventilation

Each underground vault or pit containing either pressure regulating, reducing, or limiting station must be sealed, vented or ventilated as follows:

1) When the internal volume exceeds 200 cubic feet -
   a) Be ventilated with two ducts, each having at least the ventilating effect of a 4" pipe.
      i) The ends of the ducts should be equipped with a suitable weatherproof fitting to prevent foreign matter from entering or obstructing the duct.

(Continued on next page)

ii) The horizontal section of the ducts should be as short as practical and pitched to prevent the accumulation of liquids.
iii) The number of bends and offsets should be reduced to a minimum and provisions should be incorporated to facilitate periodic cleaning.
iv) If two ducts are used, consider terminating one vent higher than the other to improve ventilation.

b) Ventilation must be adequate enough to minimize the formation of combustible gas-air mixture inside the vault or pit.
c) Ducts must terminate high enough above grade to disperse any gas-air mixture.

2) When the internal volume is more than 75 cubic feet but less than 200 cubic feet –
   a) If the vault or pit is sealed, each opening must have a tight-fitting cover without open holes through which an explosive mixture might be ignited, and there must be a means for testing the internal atmosphere before removing the cover.
   b) If the vault or pit is vented, there must be a means of preventing external sources of ignition from reaching the vault atmosphere.
   c) If the vault or pit is ventilated, paragraph 1) or 3) of this division applies.
3) If a vault or pit covered by paragraph 2) of this division is ventilated by openings in the covers or gratings and the ratio of the internal volume, in cubic feet, to the effective ventilating area of the cover or grating, in square feet, is less than 20 to 1, no additional ventilation is required.

4. Drainage and Waterproofing

1) Each vault must be designed to minimize the entrance of water.
   a) Equipment installed in vaults should be designed to continue safe operation if completely submerged.
2) A vault containing gas piping may not have a drain that is connected to any other underground structure. The drain must terminate above ground to the atmosphere.
3) Electrical equipment in vaults must conform to applicable requirements of Class 1, Group D, of the National Electrical Code, NFPA-70.

Division 5.17: Valve Installation in Plastic Pipe *(Reference 192.193)*

Each valve installed in plastic pipe must be designed so as to protect the plastic material against excessive torsional or shearing loads when the valve or shutoff is operated, and from any other secondary stresses that might be exerted through the valve or its enclosure.

1. Preventing Loads Imposed by Valve Operation

Use any of the following methods or combination of methods to prevent stresses caused by operation of the valve.

1) Use a valve with a low operating torque.
2) Anchor the valve body to resist twisting.
3) If applicable, make a transition from plastic-to-metal some distance from the valve. Plastic-to-metal transitions approximately two feet long will usually provide sufficient stabilization. However, each installation is different and must be designed to prevent excessive strain on piping.
4) Installing a protective sleeve designed to mitigate the stress imposed on the plastic pipe in the transition area between the valve and the plastic piping should be considered if undue stresses are anticipated or recommended by the manufacturer.
    a) Protective sleeves are typically lengths of either PE or PVC pipe.
    b) The protective sleeve should fully support the plastic pipe in the joint area.
    c) The protective sleeve should be of adequate length and inside diameter to ensure that the minimum bend radius is not exceeded.
    d) The annular space between the plastic pipe and the protective sleeve should provide such a fit to avoid overstressing the joint during operation.

2. Preventing Secondary Stresses

1) The transition area (from valve to pipe) should be supported by undisturbed or well-compacted soil, by bridging, or by sleeve encasement.
2) If a curb box or enclosure is used, it should not be supported by the plastic pipe and should not in any way impose a secondary stress on the plastic pipe.
3) Valves installed in thermoplastic piping that has been coiled should be suitably restrained to prevent any rotation that may occur.

Division 5.18: Protection Against Accidental Over-pressuring *(Reference 192.195)*

1) Except as provided in Division 5.19 of this Plan, each pipeline that is connected to a gas source so that the MAOP could be exceeded as the result of pressure control failure or some type of other failure, must have pressure relieving or pressure limiting devices that meet the requirements of Division 5.20 & 5.21 of this Plan.
2) Each distribution system that is supplied from a source of gas that is at higher pressure than the MAOP of the system must meet the following:
   a) Have pressure regulation devices capable of meeting the pressure, load, and other service conditions that will be experienced in normal operation of the system, and that could be activated in the event of failure of some portion of the system; and
   b) Be designed to prevent accidental over-pressuring.

1. Considerations for Inlet and Outlet Pressure Ratings

Selection of inlet and outlet pressure ratings of pressure control equipment should consider the following.

1) The maximum inlet pressure to which the regulator may be subjected, without damaging the regulator.
2) The maximum inlet pressure at which the regulator will still perform within manufacturer's specifications.
3) The maximum outlet pressure to which the regulator may be subjected, without damaging the regulator.
4) The maximum outlet pressure at which the regulator will still perform within manufacturer's specifications.
5) The maximum outlet pressure which can be safely contained by the pressure carrying components, such as diaphragm cases, actuators, pilots and control lines.

NOTE: Springs, orifices, or other parts should NOT be changed or modified without reevaluation of the above factors.

2. Over-Pressure Protection for High-pressure Distribution Systems

Suitable devices to prevent over-pressuring of high-pressure distribution systems include the following.

1) Spring-loaded relief devices meeting the provisions of ASME Boiler and Pressure Vessel Code, Section VII, Division 1.
2) A monitoring regulator installed in series with a primary regulator.
3) A regulator installed in a series that limits the inlet pressure of the primary regulator to less than the MAOP of the distribution system.
4) An automatic shut-off device installed in a series with a primary regulator that will shut-off the flow of gas at a pressure less than the MAOP of the distribution system.

(Continued on next page)

5) Pilot-operated back-pressure regulators used as relief valves and designed so that failure of the control lines will cause the regulator to open.
6) Spring-loaded diaphragm relief valves.

3. Additional Considerations

When bypass piping is included in the station design, the following considerations should be given to the following.

1) Install a regulator on the bypass piping to limit pressure less than MAOP.
2) Arranging the bypass piping for series regulators so that only one regulator at a time is being bypassed.
3) If a manually operated bypass valve is installed:
   a) Upstream and downstream gauges should be installed within sight of the person operating the manual valve so that pressures can be monitored at all times during the bypass operation.

Division 5.19: Control of Gas Pressure Delivered from High-Pressure Distribution Systems *(Reference 192.197)*

1) If the maximum actual operating pressure of the distribution system is 60 psi (414 kPa) gage, or less and a service regulator having the following characteristics is used, no other pressure limiting device is required:

   a) A regulator capable of reducing distribution line pressure to pressures recommended for household appliances.
   b) A single port valve with proper orifice for the maximum gas pressure at the regulator inlet.
   c) A valve seat made of resilient material designed to withstand abrasion of the gas, impurities in gas, cutting by the valve, and to resist permanent deformation when it is pressed against the valve port.
   d) Pipe connections to the regulator not exceeding 2 inches (51 millimeters) in diameter.
   e) A regulator that, under normal operating conditions, is able to regulate the downstream pressure within the necessary limits of accuracy and to limit the build-up of pressure under no-flow conditions to prevent a pressure that would cause the unsafe operation of any connected and properly adjusted gas utilization equipment.
   f) A self-contained service regulator with no external static or control lines.

2) If the maximum actual operating pressure of the distribution system is 60 psi (414 kPa) gage, or less, and a service regulator that does not have all of the characteristics listed in paragraph (1) of this section is used, or if the gas contains materials that seriously interfere with the operation of service regulators, there must be suitable protective devices to prevent unsafe over-pressuring of the customer's appliances if the service regulator fails.

3) If the maximum actual operating pressure of the distribution system exceeds 60 psi (414 kPa) gage, one of the following methods must be used to regulate and limit, to the maximum safe value, the pressure of gas delivered to the customer:

   a) A service regulator having the characteristics listed in paragraph (1) of this section, and another regulator located upstream from the service regulator. The upstream regulator may not be set to maintain a pressure higher than 60 psi (414 kPa) gage. A device must be installed between the upstream regulator and the service regulator to limit the pressure on the inlet of the service regulator to 60 psi (414 kPa) gage or less in case the upstream regulator fails to function properly. This device may be either a relief valve or an automatic shutoff that shuts, if the pressure on the inlet of the service regulator exceeds the set pressure (60 psi (414 kPa) gage or less), and remains closed until manually reset.
   b) A service regulator and a monitoring regulator set to limit, to a maximum safe value, the pressure of the gas delivered to the customer.

(Continued on next page)

c) A service regulator with a relief valve vented to the outside atmosphere, with the relief valve set to open so that the pressure of gas going to the customer does not exceed a maximum safe value. The relief valve may either be built into the service regulator or it may be a separate unit installed downstream from the service regulator. This combination may be used alone only in those cases where the inlet pressure on the service regulator does not exceed the manufacturer's safe working pressure rating of the service regulator, and may not be used where the inlet pressure on the service regulator exceeds 125 psi (862 kPa) gage. For higher inlet pressures, the methods in paragraph 3) a) or b) of this section must be used.

d) A service regulator and an automatic shutoff device that closes upon a rise in pressure downstream from the regulator and remains closed until manually reset.

Additional Information

1) Suitable protective devices to prevent over-pressuring a customer's appliances as described above include the following devices.
   a) Monitoring regulator.
   b) Relief valve
   c) Service regulator with internal relief valve that has sufficient capacity.
   d) Automatic shut-off devices.
2) The protective devices may be installed as an integral part of the service regulator or as a separate unit.

Division 5.20: Design of Pressure Relief and Limiting Devices *(Reference 192.199)*

Except for rupture discs, each pressure limiting and relief device must be designed as required below:

1) Must be constructed of materials such that the operation of the device will not be impaired by corrosion.
2) Contain valve and valve seats that are designed not to stick in a position that will make the device inoperative.
3) Designed and installed so that it can be readily operated to determine if the valve is free, can be tested to determine the pressure at which it will operate, and can be tested for leakage when in the closed position.
4) Have supports made of noncombustible materials.
   a) If supports are metallic, a type of dielectric insulator should be installed between the pipe and the support.
5) Have discharge stacks, vents, or out ports designed to prevent accumulation of water, ice, snow, and located where gas can discharge into the atmosphere without undue hazard.
6) Designed and installed so that the size of the openings, pipe, and fittings located between the system to be protected and the pressure relieving device, and the size of the vent line, are adequate to prevent hammering of the valve and to prevent impairment of relief capacity.
7) Where installed at a district regulator station, the station must be designed and installed to prevent any single incident such as an explosion in a vault or damage by a vehicle from affecting the operation of both the overpressure protective device and the district regulator.
   a) The operator should consider the following:
      i) Selection of a location away from vehicular traffic to reduce the possibility of damage.
      ii) Install facilities on Company owned or controlled ground.
      iii) Installation of barricades, posts, bollards, guardrails, etc.
      iv) Installation inside of ventilated building made of noncombustible materials.
      v) Installation of pressure limiting devices a sufficient distance away from the pressure relieving equipment.
8) Except for a valve that will isolate the system under protection from its source of pressure, be designed to prevent unauthorized operation of any stop valve that will make the pressure relief valve or pressure limiting device inoperative.
   a) If all regulator station piping and components are located within a restricted area that is locked and only operating personnel have access, this will be deemed sufficient.
   b) If regulator station piping and components are accessible to the public (in an open area with bollards or barricades) all valves must have a company approved locking device to prevent unauthorized operation.

Division 5.21: Required Capacity of Pressure Relieving & Limiting Stations

(Reference 192.201)

1) All pressure limiting and relieving stations must have sufficient capacity and be set to insure the following:
   a) In a low-pressure distribution system, the pressure may not cause the unsafe operation of any connected and properly adjusted gas utilization equipment.
   b) In all other distribution systems, pressure relieving or limiting devices must be set within the limitations of the following chart.

MAOP	Allowable Buildup
≥ 60 psig	+ 10% psig
≥ 12 psig < 60 psig	+ 6 psig
< 12 psig	+ 50% psig

2) When more than one regulator is installed at a station, the relief valve or other protective device must have sufficient capacity to limit downstream pressure at or below MAOP plus allowable buildup in the event there is a complete failure of the largest regulator.
   a) The relief capacity should be based on the maximum capacity of the regulator at the highest inlet pressure that the regulator could possibly be subjected.
      i) This inlet pressure may be the maximum operating pressure or the maximum allowable operating pressure of the supply gas.
   b) The regulator capacity can be calculated using the manufacturer's literature as long as the capacities are provided for when the regulator fails in the wide-open position.
      i) If the pipeline is not capable of supplying enough gas to meet the capacity of the largest regulator in the failed wide-open position, the relief capacity may be based on the maximum capacity of the pipeline supplying the station.
3) Relief valves or other pressure limiting devices must be installed at or near each regulator station in a low-pressure system, with sufficient capacity to limit pressure at or below the maximum safe operating pressure for any connected and properly adjusted gas utilization equipment.

1. Determination of Relief Valve Capacity

1) Relief devices stamped by the manufacturer with a capacity certified by Section VIII of the ASME Boiler & Pressure Vessel Code, including recertification stampings, may be considered acceptable. An adjustment should be made to determine the actual capacity at the actual operating conditions.
2) Capacity information provided in the manufacturer's literature may be used to identify the capacity of the relief device under actual operating conditions.
3) The use of published data or data otherwise provided from the manufacturer along with data calculated using recognized formulas, is acceptable.
4) Relief valve capacities are normally based on the measured inlet pressure to the relief valve with a discharge to atmosphere without vent stack piping.

Division 5.22: Instrument, Control, and Sampling Pipe and Components

(Reference 192.203)

This applies to the design of instrument, control, and sampling pipe and components. It does not apply to permanently closed systems, such as fluid-filled temperature-responsive devices.

All materials employed for pipe and components must be designed to meet the conditions of service and the following:

1) Takeoff connections and fittings or adapters must be made of suitable materials.
2) They must be able to withstand the maximum service pressure and temperature of the pipe or equipment to which they are attached.
3) Must be designed to withstand all stresses without failure due to fatigue.
4) A shutoff valve must be installed in each takeoff line as near as possible to the point of takeoff except for takeoff lines that can be isolated from sources of pressure by other valving.
5) 400° F may not be exceeded if using brass or copper materials.
6) Heat must be provided to pipe and components that may contain liquids that could freeze and cause damage.
7) Drips or drains must be installed on pipe and components that may accumulate liquids.
8) Suitable connections for cleaning out solids or deposits must be installed.
9) Proper arrangement of piping and components as well as installation of proper support must provide safety under anticipated operating stresses.
10) Slip type expansion joints may not be used. Expansion and contraction must be allowed for within the flexibility built into the system
11) Each control line must be installed separately and protected from anticipated stresses. They also must be designed and installed to prevent damage to any one control line causing both the regulator and the over pressure protective device to fail.

Division 5.23: Risers Installed After January 22, 2019 *(Reference 192.204)*

1) Riser designs must be tested to ensure safe performance under anticipated external and internal loads acting on the assembly.
2) Factory assembled anodeless risers must be designed and tested in accordance with ASTM F1973-13.
3) All risers used to connect regulator stations to plastic mains must be rigid and designed to provide adequate support and resist lateral movement. Anodeless risers used in accordance with this Division must have a rigid riser casing.

Division 5.24: Transmission Records – Pipeline Components *(Reference 192.205)*

1) For steel transmission pipelines installed after July 1, 2020, an operator must collect or make and retain for the life of the pipeline, records documenting all pipe and components were manufactured and tested in accordance with this Division. Flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi (X42) or greater than 2" must have records documenting the manufacturing specification in effect at the time of manufacture, including yield strength, ultimate tensile strength, and chemical composition of materials.
2) For steel transmission pipelines installed on or before July 1, 2020, if operators have records documenting the manufacturing standard and pressure rating for valves, flanges, fitting, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi (X42) or greater and with nominal diameters of greater than 2", operators must retain such records for the life of the pipeline.
3) For steel transmission pipeline segments installed on or before July 1, 2020, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of Division 13.15 of this Plan.

CITY OF BLOOMFIELD, IOWA

DIVISION SIX

Welding of Steel in Pipelines

49 CFR Part 192 Subpart E

Division 6.1: Welding Procedures *(Reference 192.221 & 192.225)*

This Division prescribes the minimum requirements for welding steel materials in pipelines. However, this does NOT apply to welding that occurs during the manufacture of steel pipe and components.

1) Welding must be performed by a qualified welder or welding operator in accordance with welding procedures qualified under Section 5, Section 12, Appendix A or Appendix B of API Standard 1104 or section IX of the ASME Boiler and Pressure Vessel Code. The quality of the test welds used to qualify welding procedures must be determined by destructive testing in accordance with applicable welding standard.
2) Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.
3) Qualified welding procedures and qualified in-service welding procedures can be found in the Iowa Association of Municipal Utilities Model Gas Distribution Pipeline Welding Procedures Manual.
   a) If welding procedures are used that are not found in the IAMU Model Gas Distribution Pipeline Welding Procedures Manual, records of those procedures and procedure qualification tests must be retained and followed for as long as that procedure is being used.

Division 6.2: Qualification of Welders *(Reference 192.227)*

1) Except as provided in paragraph 2) of this Division, each welder or welding operator must be qualified in accordance with section 6, section 12, Appendix A or Appendix B of SPI Std 1104, or section IX of the ASME Boiler and Pressure Vessel Code. However, a welder or welding operator qualified under an earlier edition and listed in §192.7 (incorporated references) may weld but may not requalify under that earlier edition.
2) A welder may qualify to perform welding on pipe to be operated at a pressure that produces a hoop stress of less than 20% SMYS by performing an acceptable test weld, for the process to be used, under the test set forth in section I of Appendix C of Part 192. Each welder who is to make a welded service line connection to a main must first perform an acceptable test weld under section II of Appendix C of Part 192 as a requirement of the qualifying test.
3) For steel transmission pipe installed after July 1, 2021, records demonstrating each individual welder qualification at the time of construction in accordance with this Division must be retained for a minimum of 5 years following construction.

Division 6.3: Limitations on Welders *(Reference 192.229)*

1) No welder or welding operator whose qualification is based on nondestructive testing may weld compressor station piping and components.
2) A welder or welding operator may not weld with a particular welding process unless, within a preceding 6 calendar months, the welder or welding operator was engaged in welding with that process.
3) A welder or welding operator qualified under Division 6.2 1) of this Plan;
   a) May NOT weld on pipe to be operated at a pressure that produces a hoop stress of 20% or more of SMYS unless within the preceding 6 calendar months the welder or welding operator has had one weld tested and found acceptable under either Section 6, 9, or 12 of Appendix A of API Standard 1104. Welders and welding operators may maintain an ongoing qualification status by performing welds tested and found acceptable under the above acceptance criteria at least twice each calendar year, but not at intervals exceeding 7 ½ months. A welder or welding operator qualified under and earlier edition of a standard referenced in Division 2.3 of this Plan, may weld, but may NOT requalify under that earlier edition; and,
   b) May NOT weld on pipe to be operated a pressure that produces a hoop stress of less than 20% of SMYS unless the welder or welding operator is tested in accordance with paragraph 3) a) of this Division or requalifies under paragraph 4) a) of this Division.
4) A welder or welding operator qualified under Division 6.2 of this Plan may NOT weld unless;
   a) Within the preceding 15 calendar months, but at least once each calendar year, the welder or welding operator has requalified under Division 6.2, 2) of this Plan; or
   b) Within the preceding 7 ½ calendar months, but at least twice each calendar year, the welder or welding operator has had –
      i) A production weld cut out, tested, and found acceptable in accordance with the qualifying test, or
      ii) For a welder who works only on service lines 2" or smaller in diameter, the welder has had two sample welds tested and found acceptable in accordance with the test in Section III of Appendix C.

Division 6.4: Additional Information

For all other requirements for welders and welding operators, see the IAMU Model Gas Distribution Pipeline Welding Procedures Manual.

CITY OF BLOOMFIELD, IOWA

DIVISION SEVEN

Joining of Material Other Than by Welding

49 CFR Part 192 Subpart F

Division 7.1: General Requirements *(Reference 192.271 & 192.273)*

1) This Division prescribes the minimum requirements for joining materials in pipelines, other than by welding.
2) This Division does NOT apply to joining during the manufacture of pipe or pipeline components.
3) The pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion or by anticipated external and internal loading on the pipeline.
4) Each joint must be made in accordance with written procedures that have been proven by test or experience to produce strong gastight joints.
   a) The capability of a joining method should be established by test or experience. Certification by the manufacturer is acceptable instead of testing.
   b) All mechanical joints should be designed and installed to effectively sustain the longitudinal pullout forces caused by contraction of the piping and by maximum anticipated external loading.
5) Each joint must be inspected to ensure compliance with this Division.

Division 7.2: Cast Iron Pipe Joining *(Reference 192.275)*

NOTE: The installation of new cast iron pipelines is NOT allowed by this Plan. Repairs of existing cast iron pipelines is allowed; however, replacement is recommended.

1) Each caulked bell and spigot joint in cast iron pipe must be sealed with mechanical leak clamps.
2) Each mechanical joint in cast iron pipe must have a gasket made of a resilient material as the sealing medium. Each gasket must be suitably confined and retained under compression by a separate gland or follower ring.
3) Cast iron pipe may NOT be joined by threaded joints
4) Cast iron pipe may NOT be joined by brazing.

Division 7.3: Ductile Iron Pipe Joining *(Reference 192.277)*

1) Ductile iron pipe may NOT be joined by threaded joints.
2) Ductile iron pipe may NOT be joined by brazing.

Division 7.4: Copper Pipe *(Reference 192.279)*

Copper pipe may NOT be threaded except that the coper pipe used for joining screw fittings or valves may be threaded if the wall thickness is equivalent to the comparable size of Schedule 40 or heavier.

Division 7.5: Plastic Pipe Joining Requirements *(Reference 192.281)*

1) Threaded joints or miter joints may not be used to join plastic pipe. Any plastic pipe joint produced by using solvent cement, adhesive or heat fusion may not be disturbed until it has properly set.
   a) Solvent Cement Joints
      i) All solvent cement joints must be made in accordance with 49 CFR Part 192.281(b).
   b) Heat Fusion Joints
      i) All butt fusion joints must be made by a device that holds the heater element square to the ends of the pipe or component, compresses the heated ends together, and holds the pipe in proper alignment in accordance with the appropriate procedure qualified under 49 CFR Part 192.283.
      ii) A socket heat fusion joint must made by a device that heats the mating surfaces of the pipe and component uniformly and simultaneously, to establish the same temperature. The device used must be the same device as specified by the manufacturers socket fusion joining procedure.
      iii) An electrofusion joint must be made using the equipment and techniques prescribed by the fittings manufacturer, or using the equipment and techniques shown, by testing joints to the requirements of 49 CFR Part 192.283(a)(1)(iii), to be at least equivalent to those of the fitting manufacturer.
      iv) Heat may NOT be applied with a torch or other open flame source.
   c) Adhesive Joints
      i) All adhesive joints must be made in accordance with 49 CFR Part 192.281(d).
   d) Mechanical Joints
      i) Each compression type mechanical joint on plastic pipe must be made with a gasket material that is compatible with the plastic.
      ii) Must contain a rigid internal stiffener, other than a split tubular stiffener, must be used in conjunction with coupling.
      iii) All mechanical fittings must be listed specification based upon the applicable material.
      iv) All mechanical joints or fittings installed after January 22, 2019, must be Category 1 as defined by a listed specification for the applicable material, providing a seal plus resistance to a force on the pipe joint equal to or greater than that which will cause no less than 25% elongation of pipe, or the pipe fails outside the joint area if tested in accordance with the applicable standard.

NOTE: Whenever joining dissimilar PE materials, joining will only be completed by using mechanical fittings, electro-fusion or socket fusion joining procedures.

Division 7.6: Qualified Joining Procedures *(Reference 192.283)*

1) The operator may elect to develop and qualify their own specific joining procedures or may follow the joining procedures qualified by the pipe or fitting manufacturer. The operator is ultimately responsible for ensuring that the joining procedure being used is qualified in accordance with 49 CFR Part 192.283.
2) When the manufacturer's qualified joining procedure is used, the written procedures must be available to all joining personnel. The manufacturers written qualified joining procedures are often included in the packaging with each fitting.
3) The most important objective in any gas piping installation is be sure that the pipe joints are gas tight.

   NOTE #1: Specific qualified joining procedures can be found in the Operations and Maintenance Plan Written Procedures Part 1.

Division 7.7: Qualifying Persons to Make Joints *(Reference 192.285)*

1) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by the following;
   a) Appropriate training or experience in the use of the procedure; and
   b) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and testing found in paragraph 2) of this Division.
2) The specimen joint must be –
   a) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and
   b) In the case of a heat fusion, solvent cement, or adhesive joint:
      i) The joint is tested under any one of the methods listed in Division 7.6 of this Plan for heat fusion joints (except for electrofusion joints).
      ii) The joint is visually inspected and tested in accordance with ASTM F2620-12 that is applicable to type of joint and material being tested.
      iii) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or
      iv) Cut into at least 3 longitudinal straps, each of which is –
         (1) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and
         (2) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.

(continued on next page)

3) A person must be requalified in the joining procedure that is used to make joints at least once each calendar year not to exceed 15 months, or after any joint made in the field is found unacceptable during pressure testing.
4) Each operator shall use their Operator Qualification Plan to ensure that each person making joints in plastic pipelines is qualified to do so.
5) For transmission pipe installed after July 1, 2021, records demonstrating each person's plastic pipe joining qualifications at the time of construction must be retained for a minimum of 5 years following construction.

Division 7.8: Inspection of Joints *(Reference 192.287)*

No person may inspect joints in plastic pipelines unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.

CITY OF BLOOMFIELD, IOWA

DIVISION EIGHT

Construction Requirements:

Transmission Lines & Distribution Mains

49 CFR Part 192 Subpart G

Division 8.1: General Information *(Reference 192.301, 192.303 & 192.305)*

1) Each transmission line and distribution main must be constructed according to the construction standards found in this Division of this Plan. If the construction standards found in this Division of this Plan are not suitable for a specific installation, the Operator is responsible for either developing or following a written specification that is consistent with the requirements of 49 CFR Part 192 Subpart G.
2) Each transmission line or distribution main must be inspected to ensure that it has been constructed according to the standards found in this Plan or according to a written specification that has been chosen or developed for a specific installation.

Division 8.2: Inspection of Pipe and Components Before and During Installation *(Reference 192.307)*

All pipe and components must be visually inspected before and during installation to ensure that damage that could impair serviceability has not occurred during handling or installation practices.

Additional Information:

1) See IAMU Procedure #2.3 – Visually Inspect Pipe and Components Prior to Installation for specific procedure details.

Division 8.3: Repair of Steel Pipe *(Reference 192.309)*

NOTE: For the purpose of this Division, a "dent" is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe-wall thickness. The depth of a dent is measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe.

1) Each imperfection or damage found that impairs the serviceability of steel pipe, must be repaired or removed.
2) If a repair is made by grinding out the imperfection, the remaining wall thickness of the steel pipe must be equal to either:
   a) The minimum wall thickness required by the tolerances in the specification to which the pipe was manufactured; or
   b) The nominal wall thickness required for the design pressure of the pipeline.
3) Dents must be removed from steel pipe to be operated at a pressure that produces a hoop stress of 20% or more of SMYS, unless the dent is repaired by a method that reliable engineering tests and analysis show can permanently restore the serviceability of pipe;
   a) A dent that contains a stress concentrator such as a scratch, gouge, groove, or arc burn.
   b) A dent that affects the longitudinal weld or a circumferential weld.
   c) In pipe to be operated at a pressure that produces a hoop stress of 40% or more of SMYS, a dent that has a depth of –
      i) More than ¼" in pipe 12 ¾" or less in outer diameter
      ii) More than 2% of the nominal pipe diameter in pipe over 12 ¾" in outer diameter.
4) Each arc burn made on steel pipe to be operated at 40% or more of SMYS must be repaired or removed. If a repair is made by grinding, the arc burn must be completely removed and the remaining wall thickness must be at least equal to either:
   a) The minimum wall thickness required by the tolerances in the specification to which the pipe was manufactured; or
   b) The nominal wall thickness required for the design pressure of the pipeline.
5) A gouge, groove, arc burn, or dent may not be repaired by insert patching or by pounding out.
6) Each gouge, groove, arc burn, or dent that is removed from a length of pipe must be removed by cutting out the damaged portion as a cylinder.

Additional Information:

1) To determine the depth of a dent, place a straight edge that spans the dented surface of the pipe and measure the maximum distance between the dent and the straight edge.
2) To determine if an arc burn has been completely removed by grinding, swab the area with a 20% solution of ammonium persulfate. If a blackened spot appears after applying the ammonium persulfate, additional grinding is necessary. When swabbing with ammonium persulfate no longer produces a black spot, the arc burn has been completely removed.

Division 8.4: Repair of Plastic Pipe *(Reference 192.311)*

Any imperfection or damage found that would impair the serviceability of plastic pipe must be repaired or removed.

1) Any gouge, scratch or imperfection found that results in 10% or more of the nominal wall thickness being removed or missing must be cut out and replaced.

Division 8.5: Steel Pipe Bends and Elbows *(Reference 192.313 & 192.315)*

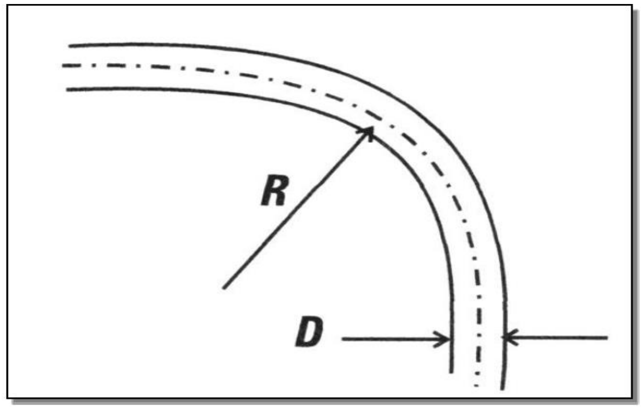
1) Wrinkle bends are NOT allowed for use according to this Plan.
2) Any field bending of steel pipe must comply with the following:
   a) A bend must not impair the serviceability of the pipe.
   b) Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage.
   c) On pipe containing a longitudinal weld, the weld must be as near as practicable to the neutral axis of the bend unless –
      i) The bend is made with an internal bending mandrel; or
      ii) The pipe is 12" or less in outside diameter or has a diameter to wall thickness ratio less than 70.
3) Each circumferential weld of steel pipe which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process.
4) Wrought-steel welding elbows and transverse segments of these elbows may not be used for changes in direction on steel pipe that is 2" or more in diameter unless the arc length, as measured along the crotch, is at least 1".

NOTE: See IAMU Procedure #2.11 – Field Bending of Steel Pipe for specific steel service line bending procedures. All bends made for steel mains should be made by the pipe manufacturer or contractor qualified to make steel pipe bends.

Division 8.6: Plastic Pipe Bends *(Reference 192.313)*

Definitions:

Minimum Long-term Bending Radius – Is a radius that is to remain on the plastic pipe after installation is complete and the pipe is put into service.



Minimum Short-term Bending Radius – Is a radius that is temporarily allowed during plowing or insertion activities that exceeds the long-term bending radius but does not kink the pipe.

1) An operator may not install plastic pipe with a bend radius that is less than the minimum bend radius specified by the manufacturer for the diameter of the pipe being installed.
   a) The allowable bend radius for plastic pipe is determined by the pipe diameter and dimension ratio.
   b) Plastic pipe installed without joints can be bent into a smaller radius than plastic pipe with joints.
   c) Considerable force may be required to cold field bend the pipe and the pipe may spring back if proper restraints such as blocking or sand bags are not used.
      i) Before final backfill, the restraints must be removed and any voids must be filled with properly compacted backfill.

The tables found on the following page were calculated using the following equation provided in the Performance Pipe Technical Note PP 819-TN Field Bending of DriscoPlex Pipe.

$$R = \alpha(OD)$$

R = minimum bend radius for the pipe (inches)

α = minimum bend ratio

OD = pipe outside diameter

(continued on next page)

Minimum Long-Term Bending Radius Table (without fittings)

Nominal Pipe Size	Standard Dimension Ratio (SDR)	Wall Thickness (in inches)	Outside Diameter (in inches)	Minimum Bending Radius
½” CTS	7	0.090	0.625	20 x pipe OD (12.5”)
¾” IPS	11	0.095	1.050	25 x pipe OD (26.25”)
1” IPS	11	0.120	1.315	25 x pipe OD (32.875”)
2” IPS	11	0.216	2.375	25 x pipe OD (59.375”)
3” IPS	11	0.318	3.50	25 x pipe OD (87.5”)
4” IPS	11	0.391	4.50	25 x pipe OD (112.5”)
6” IPS	11	0.576	6.625	25 x pipe OD (165.625”)

Minimum Long-Term Bending Radius Table (with fittings)

Nominal Pipe Size	Standard Dimension Ratio (SDR)	Wall Thickness (in inches)	Outside Diameter (in inches)	Minimum Bending Radius
All	All	All	All	100 x pipe OD

Minimum Short-Term Bending Radius Table (without fittings)

Standard Dimension Ratio	Minimum Bending Radius
Less than or equal to 9	10 x pipe OD
Greater than 9, less than or equal to 13.5	13 x pipe OD
Greater than 13.5, less than or equal to 21	17 x pipe OD
Greater than 21	20 x pipe OD

Division 8.7: Protection from Hazards *(Reference 192.317)*

1) The Operator must take all reasonable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or sustain abnormal loads.
2) Each aboveground transmission line or main must be protected from accidental damage by vehicular traffic or other similar causes, by either being installed at a safe distance from traffic routes or by installing barricades.

1. Natural Hazards

1) If a transmission line or main installation crosses areas that are normally under water or subject to flooding, sufficient weight or anchorage should be installed to prevent the pipe from floating.
2) For transmission lines or mains installed in an area prone to washout or soil erosion due to water run-off, the pipeline should be installed at a sufficient depth to protect the pipeline from reasonably expected washouts from a 100-year flood event.
   a) Additional protection from soil erosion or washouts can be provided by installing concrete protective mats and/or building terraces or dikes.
3) Considerations should be given to the installation of isolation valves in certain areas prone to flooding. If possible, the valve should be installed above the 100-year flood elevation.

2. Outside Forces

1) Aboveground transmission lines and main facilities include but are not limited to the following;
   a) Town boarder stations and district regulator stations.
   b) Individual farm taps located off of transmission lines.
   c) Isolation valves (hairpin valves).
   d) Blowdown valves.
   e) Meter set installations.
2) When installing above ground facilities, special consideration should be given to the following factors to determine installation placement and the need for additional protection;
   a) Proximity to public roads (state or federal highway, county highway, city street, etc.)
   b) Proximity to private driveways (residential, commercial, industrial, etc.)
   c) Speed limit and direction of travel.
   d) Terrain features such as steep or shallow ditches, hillsides, etc.
3) If it can be reasonably anticipated that damage could occur at the aboveground installation location, the Operator should install barricades, bollards, fencing, or some type of protection that is suitable for the specific installation.

Division 8.8: Installation of Pipe in a Ditch *(Reference 192.319)*

1) When installed in a ditch, each transmission line that is to be operated at a pressure that produces a hoop stress of 20% or more of SMYS must be installed so that the pipe fits the ditch to minimize stresses and protect the pipe coating from damage.
   a) See IAMU Procedure #2.4 – Installation of Pipe in a Ditch for specific procedures.
2) When the ditch is backfilled, it must be backfilled in a manner that provides firm support under the pipe and prevents damage to the pipe and pipe coating from equipment and backfill material.
   a) See IAMU Procedure 2.5 - Backfilling for specific procedures.

Division 8.9: Installation of Plastic Pipe *(Reference 192.321)*

1. Below Ground Installations

1) Plastic pipe must be installed below ground level except as described in section 2 found below.
2) If installed in a vault or other below grade structure, the plastic pipe must be completely encased in gas-tight metal pipe with fittings that are adequately protected from corrosion.
3) Must be installed to minimize shear or tensile stresses.
   a) Installed with slack in the pipe to prevent stresses caused by contraction and expansion.
   b) When long sections of pipe have been assembled outside of and alongside the ditch, the Operator should avoid placing any excessive strain on the pipe that could cause a joint to fail or the pipe to buckle while lowering into the ditch. This may be accomplished by lowering the pipe into the ditch using excavation equipment with slings or padded harnesses.
4) Any plastic pipe being installed must meet the minimum wall thickness requirements as described in Division 4.3.1 of this Plan for the specific pipe being installed.
5) Tracer wire must be installed for all below ground plastic pipe installations. The tracer wire being installed must be resistant to corrosion by using copper coated wire or other industry approved methods.
   a) See IAMU Procedure #2.7 – Installing Tracer Wire, for specific installation procedures.
6) Plastic pipe that is being encased, must be inserted into the casing pipe in a manner that will not damage the plastic pipe. Special care must be taken at entrance and exit points of the casing and the leading end of the plastic pipe must be closed before insertion.
   a) See IAMU Procedure #2.8 – Installation and Maintenance of Casings, as well as IAMU Procedure #8.18 – Installing PE Pipe as a Liner, for specific installation procedures.

2. Above Ground Installations

1) Plastic pipe may temporarily be installed above ground under the following conditions:
   a) It must be verified that the pipe has not exceeded the manufacturers recommended aboveground UV exposure limit or 2 years, whichever is less.
   b) The pipe must be protected from external forces by placing physical barriers, barricades or installing fencing to maintain safe distance from the pipe. Additional signage or markers should be considered being placed near the pipeline as well.
   c) The pipe must adequately resist exposure to UV light and high and low temperatures.
      i) The pipe should be installed with enough slack to be able to withstand contraction and expansion rates due to greater variations in aboveground temperature changes.

(continued on next page)

2) Plastic pipe may be installed on bridges if it is installed in a metallic casing, protected from UV light, and does not exceed the temperature limitations of Division 4.3 & 4.3.1 of this Plan.
3) Plastic mains may terminate above ground level if they meet the following:
   a) The above ground level portion of the plastic main is protected against deterioration and external damage.
   b) The plastic main is NOT used to support external loads.
   c) Installations of risers at regulator stations must meet the design requirements found in Division 5.23 of this Plan.

Division 8.10: Casings *(Reference 192.323)*

1) Each casing used on a transmission line or main under a highway or railroad must comply with the following:
   a) The casing must be designed to withstand superimposed loads.
   b) If there is a possibility of water entering the casing, the ends must be sealed.
   c) If the ends of an unvented casing are sealed and the seal is strong enough to retain the maximum allowable operating pressure of the carrier pipe, the casing must be designed to hold this pressure at a stress level of not more than 72% of SMYS.
   d) If vents are installed on a casing, the vents must be protected from the weather to prevent water or debris from entering the casing vent pipe.
2) The Operator may choose to have casing installations designed by a licensed engineer specific to each individual installation or follow IAMU Procedure #2.8 – Installation and Maintenance of Casings. All designs must meet the requirements listed above.

Division 8.11: Underground Clearance *(Reference 192.325)*

1) All transmission lines must be installed with a minimum of 12" separation from any other underground structure not associated with the pipeline.
   a) If a 12" separation cannot be attained, pipeline protection should be installed by one of the following means or additional means that provide adequate protection:
      i) Encasement of the pipeline with concrete, PE or vulcanized elastomer.
      ii) The space between the pipeline and the non-associated structure can be filled with sand/cement bags, concrete pads, or open-cell polyurethane pads.
2) All mains must be installed with enough clearance from other underground utilities and structures to allow for proper maintenance and to protect from damage.
   a) It is recommended that a minimum of 12" of separation is provided.
3) All plastic transmission lines or mains must also be protected with sufficient clearance from any source of heat that could damage or impair the serviceability of the pipe.
   a) It is recommended that a minimum of 12" of separation is maintained from other heat sources.
   b) If 12" of separation cannot be attained, insulation or heat shielding should be installed to provide proper protection.
4) See IAMU Procedure #2.4 – Installing Pipe in a Ditch, IAMU Procedure #2.5 – Backfilling and IAMU Procedure #2.6 – Installation of Pipelines by Trenchless Methods for additional details.

Division 8.12: Cover Requirements *(Reference 192.327)*

1) Depth of cover is measured as the distance from the top of the pipeline to ground level at final grade. See the tables below for minimum cover requirements for the installation of transmission pipelines, distribution mains and service lines.
2) If minimum cover requirements cannot be obtained, due to an underground obstruction, the pipeline must be installed with additional protection to withstand anticipated external loads such as being installed in a casing.

Transmission Pipelines

Location	Normal Soil (in inches)	Consolidated Rock (in inches)
Class 1 locations	30	18
Class 2, 3, & 4 locations	36	24
Drainage ditches of public roads & railroad crossings	36	24
Navigable stream or river	48	24

Distribution Mains

Location	Depth of Cover (in inches)
All locations	24

Service Lines

Location	Depth of Cover (in inches)
Private Property	12
Right of way, roads or streets	18

3) Distribution mains may be installed with less than 24" of cover if the law of the State or municipality -
   a) Establishes a minimum cover of less than 24".
   b) Requires that distribution mains be installed in a common trench with other utility lines; and
   c) Adequately protects the pipeline from potential damage caused by external forces.

Additional Information:

1) See IAMU Procedure #2.4 – Installing Pipe in a Ditch, IAMU Procedure #2.5 – Backfilling and IAMU Procedure #2.6 – Installation of Pipelines by Trenchless Methods for additional details.

Division 8.13: Additional Construction Requirements for Steel Pipe Using Alternative MAOP *(Reference 192.328)*

NOT APPLICABLE FOR USERS OF THIS PLAN: Any Operator using an alternative MAOP calculated by 49 CFR Part 192.620 must develop their own processes and procedures for meeting the requirements of 49 CFR Part 192.328.

Division 8.14: Installation of Plastic Pipelines by Trenchless Excavation *(Reference 192.329)*

1) All plastic pipelines installed by horizontal directional drilling, pneumatic mole, plowing, or any other approved trenchless method must include the following:
   a) The pipe being pulled through the ground must incorporate the use of a *weak link* to ensure that the pipe is protected from damage by excessive tensile forces.
      i) A *weak link* is a device or method used when pulling PE pipe that ensures damage will not occur to the pipeline by exceeding maximum tensile stress allowed for the specific pipe being pulled.
   b) Provide adequate clearance from other underground utilities as required in Division 8.11 of this Plan.
2) See IAMU Procedure #2.6 - Installation of Pipelines by Trenchless Methods for specific installation procedures.

CITY OF BLOOMFIELD, IOWA

DIVISION NINE

Customer Meters, Service Regulators & Service Lines

49 CFR Part 192 Subpart H

Division 9.1: General Information *(Reference 192.351)*

This Division in this Plan describes the minimum requirements for installing customer meters, service regulators, service lines, service line valves, and service line connections to mains.

Division 9.2: Customer Meters & Regulators: Location *(Reference 192.353)*

1. Outdoor Installations

1) If possible, meter sets should be installed outdoors.
2) Must be installed in a readily accessible location to allow for the following:
   a) Operation of shut-off valve during emergencies as well as for routine shut-offs.
   b) Meter reading.
   c) Meter change outs.
   d) Inspection, repairs and maintenance.
3) All piping and components must be coated or painted to provide protection against corrosion.
4) Must be installed in a location that provides protection from damage. Consideration should be given to the following:
   a) Protection from falling objects such as snow or ice from a roof.
   b) Protection from reasonably anticipated vehicular traffic.
5) Meter sets must not be installed within 3 feet of the following:

   NOTE: 3 feet is measured from the center of the regulator vent, not the meter.

   a) Potential ignition sources.
   b) Windows, doors, or building openings which may be used as emergency exists.
   c) Air intakes.
6) Meter sets must not be installed in contact with the soil or other potentially corrosive materials.
7) See IAMU Procedure #3.0 – Installing Customer Meters and Regulators for specific procedures.

2. Indoor Installations

1) If possible, a readily accessible shut-off valve should be installed outdoors.
2) Must be installed in a readily accessible location.
3) Each service regulator must be installed as near as practical to the point where the service line enters the building. If possible, the service regulator should be installed outdoors.
   a) If the service regulator is installed indoors, the vent must be piped back outdoors as described in IAMU Procedure #3.0 – Installing Customer Meters and Regulators.
4) Must be installed in a ventilated place and at least 3 feet from any sources of ignition or any source of heat which may damage the meter.
   a) Meters and service regulators should not be installed in confined engine, boiler, heater, electrical rooms, or in living quarters, closets, restrooms, or similar confined locations.
5) If the service regulators are installed in series, where feasible, the upstream regulator must be located outside the building, unless it is located in a separate metering or regulating building.
6) See IAMU Procedure #3.0 – Installing Customer Meters and Regulators for specific procedures.

Division 9.3: Customer Meters & Regulators: Protection from Damage

(Reference 192.355)

1) If the customer's equipment may create either a vacuum or back pressure, a device must be installed to protect the system. The following devices may be installed:
   a) Automatic shut-off valve with manual reset (for decreasing or increasing pressure).
   b) Restricting orifice.
   c) Regulating device set to close at a predetermined value (for decreasing or increasing pressure).
   d) If flow reversal is a possibility, either a check valve or a protective device that provides a gas tight shut-off should be used.
2) Service regulator and relief vents must terminate outdoors and the termination point must be:
   a) Rain and insect resistant.
      i) Pointed down with a screen.
   b) Located at a place where gas from the vent can escape freely into the atmosphere and 3 feet away from any ignition source or opening into the building.
      i) If necessary, to meet the 3-foot requirement, the vent may be piped away from ignition sources or openings into buildings. The vent piping must meet the following requirements:
         (1) The piping must be constructed of black iron, galvanized, or copper piping. PVC or plastic piping may not be used.
         (2) The piping must be at least the same size or larger as the regulator or relief vent. The vent size may not be reduced.
         (3) The piping must terminate pointing downward with a screen installed.
   c) Be protected from damage caused by submergence in areas prone to flooding.
      i) The vent may be piped vertically above the anticipated flood level according to the requirements of b) above.
      ii) If the vent is not piped above the anticipated flood level, the service should be shut-off, the meter and regulator removed and any open piping sealed to prevent water from entering.
3) Any pit or vault that contains a customer meter or regulator at a place where vehicular traffic is anticipated must be able to support the weight of that traffic.
4) See IAMU Procedure #3.0 – Installing Customer Meters and Regulators for specific requirements.

Division 9.4: Customer Meters & Regulators: Installation *(Reference 192.357)*

1) All meters and regulators must be installed to minimize anticipated stresses on all piping and components. If necessary, the following may be installed:
   a) Meter bars.
   b) Adjustable meter/riser brackets.
   c) Pipe stands, supports or hangers.
      i) If using pipe stands, supports or hangers, some type of dielectric barrier must be installed to provide separation between the pipe and the pipe stand.
         (1) A dielectric barrier is a piece of rubber, rock guard, or some type of non-metallic material placed in between the pipe support and the pipe.
   d) Blocking installed underneath the meter to provide support.
   e) Swing joints may also be installed to reduce piping stress.
2) When close all-thread nipples are used, the wall thickness remaining after the threads are cut must meet the minimum wall thickness requirements of Division 4.2.2 of this Plan.
3) Connections made of lead or other easily damaged materials may not be used in the installation of meters and/or regulators.
4) Each regulator that might release gas must be vented to the outside atmosphere as described in IAMU Procedure #3.0 – Installing Customer Meters and Regulators.

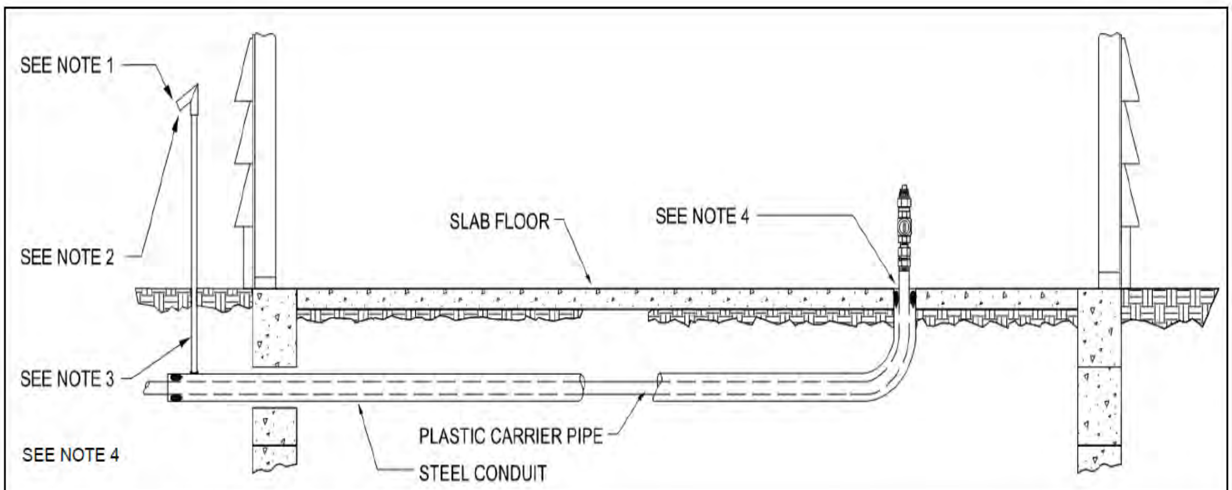
Division 9.5: Customer Meter Installations: Operating Pressures

(Reference 192.359)

1) A meter may not be used at a pressure that is more than 67% of the manufacturer's shell test pressure.
2) All installed meters manufactured after November 12, 1970 must have been tested to a minimum of 10 psi gage.
   a) Any meter installed must have an MAOP (established by the manufacturer) higher than the anticipated operating pressure flowing through the meter.
3) A rebuilt or repaired tinned steel case meter may not be used at a pressure that is more than 50% of the pressure used to test the meter after rebuilding or repairing.

Division 9.10: Installation of Service Lines *(Reference 192.361)*

1) *Depth of Installation:* Each buried service line must be installed with at least 12 inches of cover in private property and at least 18 inches of cover in streets and roads. See IAMU Procedure #3.1 – Install Steel Service Lines and IAMU Procedure #3.2 – Install Plastic Service Lines.
   a) If an underground structure prevents the installation at those required depths, the service line must be installed so that it can withstand any anticipated external loads. This may be accomplished by installing a casing or by installing a heavier walled pipe.
2) *Support and Backfill:* Each service line must be properly supported on undisturbed or well compacted soil, and the material used for backfill must be free of materials that could damage the pipe or its coating. See IAMU Procedure #2.5 - Backfilling for specific requirements.
3) *Grading for Drainage:* Where condensate in the gas might cause interruption in the gas supply to the customer, the service line must be graded to drain into the main or into drips at the low points in the service line.
4) *Protection Against Strain and External Loading:* Each service line must be installed to minimize anticipated strain and external loading.
5) *Installation of Service Lines into Buildings:* All alternatives should be considered before installing a service line into a building (through foundation wall) as this practice is NOT recommended. If this installation method is the only option, the underground service line installed below grade through the outer foundation wall of a building must provide the following –
   a) If the service line is metallic, it must be protected against corrosion and sealed at the foundation wall to prevent leakage into the building.
   b) If the service line is plastic, it must be protected from shearing action and backfill settlement and sealed at the foundation wall to prevent leakage into the building.
   c) See illustration below for details.

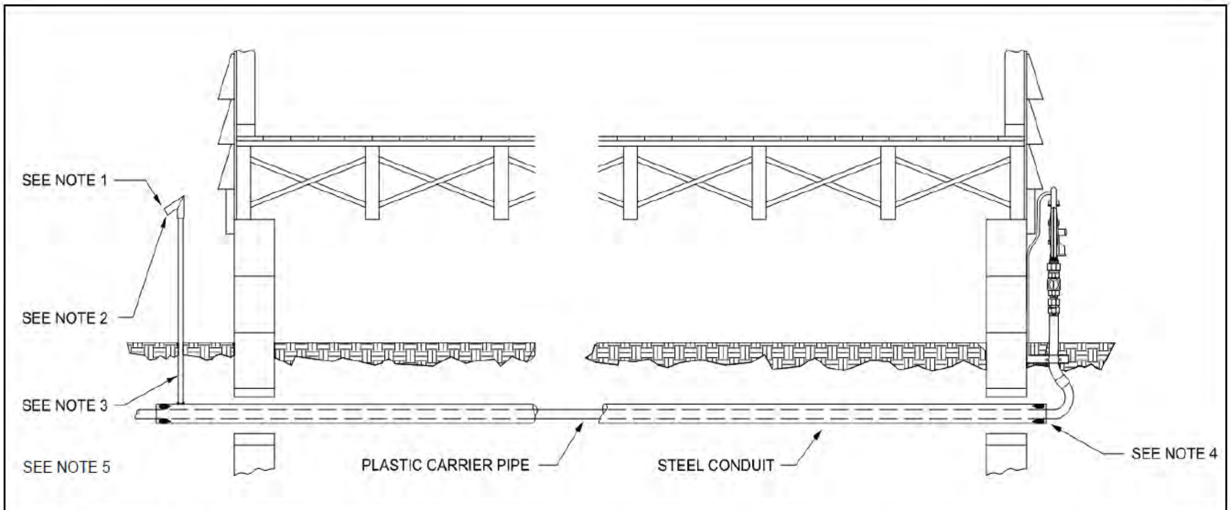


Note 1 Approved vent with insect screen.
Note 2 Vent outlet should be high enough to avoid inundation by flooding or burial by snow. Use of bollards or similar device should be considered to protect against vehicle damage.
Note 3 Vent pipe at low end of casing to be connected to side or bottom of conduit.
Note 4 Install cathodic protection and trace wire according to operator's standard.

(continued on next page)

6) *Installation of Service Lines Under Buildings:* All alternatives should be considered before installing a service line under a building, as this practice is NOT recommended. If a service line is installed under a building the following requirements must be met.

   a) It must be encased in gas tight conduit.
   b) The conduit and service line must extend into a normally usable and accessible part of the building.
   c) The space between the conduit and the service line must be sealed to prevent gas leakage into the building and, if the conduit is sealed at both ends, a vent line from the annular space must extend to a point where gas would not be a hazard, terminate above ground, and be rain and insect resistant.
   d) See illustration below for details.



Note 1 Approved vent with insect screen.
Note 2 Vent outlet should be high enough to avoid inundation by flooding or burial by snow. Use of bollards or similar device should be considered to protect against vehicle damage.
Note 3 Vent pipe at low end of casing to be connected to side or bottom of conduit.
Note 4 Seal conduit with rubberized sealing device or other method.
Note 5 Install cathodic protection and trace wire according to operator's standard.

7) *Locating Underground Service Lines:* All underground plastic service lines that are not encased, must have a tracer wire installed to provide a means of locating. See IAMU Procedure #2.7 - Installing Tracer Wire for specific requirements.

Division 9.11: Service Lines – Valve Requirements *(Reference 192.363)*

1) All service lines must have a valve installed upstream (before) the meter and/or regulator that meets the following requirements:
   a) Meets the material and design requirements found in Division 2 and 4 of this Plan.
   b) A soft seat service line valve may NOT be installed if the ability of the gas flow could be affected by exposure to anticipated heat.
   c) All high-pressure service line valves, must be designed and constructed to minimize the possibility of the valve core being removed other than with specialized tools.

Additional Information:

1) To ensure that all service line valves meet the requirements above, only install service line valves that have been approved for natural gas use at the desired pressure requirements.
2) See IAMU Procedure #3.4 – Install Service Line Valves Upstream of Customer Meter for details.

Division 9.12: Service Lines – Location of Valves *(Reference 192.365)*

1) All service lines must have a valve installed upstream (before) the meter and/or regulator.
2) All service line valves must be installed in a readily accessible location, that, if possible, is outside of the building.
3) All underground service line valves (curb valves) must be installed in a covered durable valve box or standpipe that allows ready operation of the valve and is supported independently of the service line.
4) For above ground service line valve installation requirements, see IAMU Procedure #3.4 – Install Service Line Valves Upstream of Customer Meter.
5) For below ground service line valve (curb valve) installation requirements, see IAMU Procedure #3.6 – Install Excess Flow Valves or Curb Valves.

Division 9.13: Service Lines – Requirements for Connections to Main Piping
(Reference 192.367)

1) Location
   a) All service line connections to a main must be located on the top of the main, or if that is not practical, on the side of the main.
   b) If not practical to install on the top or side of the main, a suitable protective device must be installed to minimize the possibility of dust and moisture being carried from the main into the service line.
2) Compression-Type Connection Requirements
   a) Must be designed and installed to effectively sustain longitudinal pull-out or thrust forces caused by contraction or expansion and external or internal loading.
   b) All gaskets used in compression-type connections must be made of materials that are compatible with the kind of gas in the system.
   c) If used on plastic pipelines, the connection must be Category 1 that provides a seal plus resistance to a force on the pipe joint equal to or greater than that which will cause no less than 25% elongation of the pipe, or the pipe fails outside the joint area.
3) See IAMU Procedure #3.1 – Install Steel Service Lines, IAMU Procedure #3.2 – Install Plastic Service Lines and Part Seven – Tapping and Stopping of the O&M Written Procedures for additional details.

Division 9.14: Service Lines – Connections to Cast Iron or Ductile Iron Mains
(Reference 192.369)

1) Each service line connected a cast iron or ductile iron main must connected by a mechanical clamp, by drilling and tapping the main, or by another method meeting the requirements of Division 7.1 of this Plan.
2) If a threaded cap is being inserted, it must meet the requirements of **Division 5.8 of this Plan**.

NOTE: This Plan does NOT include procedures for connections to cast iron or ductile iron main as these materials are not present in any municipally owned gas system in Iowa.

Division 9.15: Service Lines – Steel *(Reference 192.371)*

1) All service lines that are to be operated at a pressure less than 100 psi, must be constructed of steel pipe that is designed for at least 100 psi.
2) See IAMU Procedure #3.1 – Install Steel Service Lines for additional details.

Division 9.16: Service Lines – Cast Iron and Ductile Iron *(Reference 192.373)*

1) Cast or ductile iron pipe less than 6" in diameter may not be installed for service lines.
2) If cast or ductile iron pipe is installed for use as a service line, the part of the service line that extends through the building wall must be made of steel pipe.
3) A cast iron or ductile iron service line may not be installed in unstable soil or under a building.

NOTE: This Plan does NOT include procedures for installing cast iron or ductile iron services as the installation of these materials is not recommended.

Division 9.17: Service Lines – Plastic *(Reference 192.375)*

1) All plastic service lines must be installed below ground level, except for the following:
   a) Temporarily installed above ground following guidelines in Division 8.9 of this Plan.
   b) May terminate above ground level outside of the building, if:
      i) The above ground portion of the plastic service line is protected against deterioration and external damage.
      ii) It does not support external loads.
      iii) The riser meets the design requirements of Division 5.23 of this Plan.
2) All plastic service lines inside a building must be protected against external damage.
3) See IAMU Procedure #3.2 – Install Plastic Service Lines for additional details.

Division 9.18: Installation of Plastic Service Lines by Trenchless Excavation *(Reference 192.376)*

1) Plastic service lines installed by trenchless methods (horizontal directional drilling, pneumatic mole, plowing or planting) must comply with the following:
   a) Provide sufficient clearance for installation and maintenance activities from other underground utilities and structures at the time of installation.
   b) For each pipeline section, plastic pipe and components that are pulled through the ground must incorporate the use of a "weak link" as defined in Division 2.3 of this Plan, to ensure the pipeline will not be damaged by any excessive pulling forces.
2) See IAMU Procedure #2.6 – Installation of Pipelines by Trenchless Methods for specific details.

Division 9.19: Service Lines - Copper *(Reference 192.377)*

1) Each copper service line installed within a building must be protected against external damage.

NOTE: This Plan does NOT include procedures for the installation of copper service lines as this practice is not recommended.

Division 9.20: New Service Lines Not in Use *(Reference 192.379)*

1) All service lines not placed in service at the time of installation must comply with at least one of the following until the service is activated:
   a) The service valve must be closed and have locking device or other means designed to prevent the operation of the valve by unauthorized users.
   b) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.
   c) The customers piping must be physically disconnected from the gas supply and the open ends of the pipe sealed.
2) See IAMU Procedure #3.3 – Temporary Isolation of Service Lines and Service Discontinuance for specific details.

Division 9.21: Excess Flow Valve Performance Standards *(Reference 192.381)*

1) Excess flow valves (EFVs) to be used on service lines that operate continuously throughout the year at a pressure not less than 10 psi must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer's written specification, to ensure that each valve will:
   a) Function properly up to the maximum operating pressure to which it is rated.
   b) Function properly at all temperature reasonably expected in the operating environment of the service line.
   c) At 10 psi –
      i) Close at, or not more than 50% above, the rated closure flow rate specified by the manufacturer, and
      ii) Upon closure, reduce gas flow –
         (1) For an EFV designed to allow pressure to equalize across the valve, to no more than 5% of the manufacturer's specified closure flow rate, up to a maximum of 20 cubic feet per hour, or
         (2) For an EFV designed to prevent equalization of pressure across the valve, to no more than 0.4 cubic feet per hour, and
   d) Not close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate.
2) An operator must mark or otherwise identify the presence of an EFV in the service line.
3) An operator shall locate the EFV as near as practical to the fitting connecting the service line to its source of gas supply.
4) An operator should NOT install an EFV on a service line where the operator has prior experience with contaminants in the gas stream, where these contaminants could be expected to cause the EFV to malfunction or where the EFV would interfere with necessary operation and maintenance activities on the service, such as blowing liquids from the line.

Division 9.22: Excess Flow Valve Installation *(Reference 192.383)*

NOTE: See IAMU Procedure #3.6 – Install Excess Flow Valves or Curb Valves for installation procedures.

Division Definitions:

1) *Branched Service Line* – A gas service line that begins at the existing service lie or is installed concurrently with the primary service line but serves a separate residence.
2) *Replaced Service Line* – A gas service line where the fitting that connects the service line to the main is replaced or the piping connected to this fitting is replaced.
3) *Service Line Serving Single-Family Residence* – A gas service line that begins at the fitting that connects the service to the main and servs only one single-family residence (SFR).

Installation Requirements:

1) After April 14, 2017, an EFV meeting the performance standards of 9.21 of this Plan must be installed any new or replaced service line serving the following types of services before the line is activated:
   a) A single service line to one single-family residence (SFR).
   b) A branched service line to a SFR installed concurrently with the primary SFR service line (a single EFV may be installed to protect both service line).
   c) A branched service line to a SFR installed off a previously installed SFR that does not already contain an EFV.
   d) Multifamily residences with known customer loads not exceeding 1,000 SCFH (standard cubic feet per hour), at the time of service installation based on installed meter capacity.
   e) A single, small commercial customer served by a single service line with a known customer load not exceeding 1,000 SCFH at the time of meter installation, based on installed meter capacity.
   f) An operator must mark or otherwise identify the presence of an EF in the service line.

Installation Exceptions:

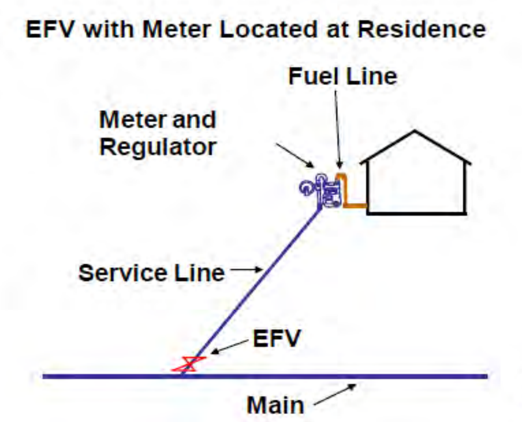
1) An EFV does NOT need to be installed if one or more of the following conditions is met:
   a) The service line does not operate at or above a pressure of 10 psi throughout the year.
   b) The operator has prior experience with contaminants in the gas stream that could interfere with the EFVs operation or cause a loss of service to the customer.
   c) An EFV could interfere with necessary operation or maintenance activities, such as blowing liquids from the line.
   d) An EFV meeting the performance standards found in Division 9.21 of this Plan is not commercially available.

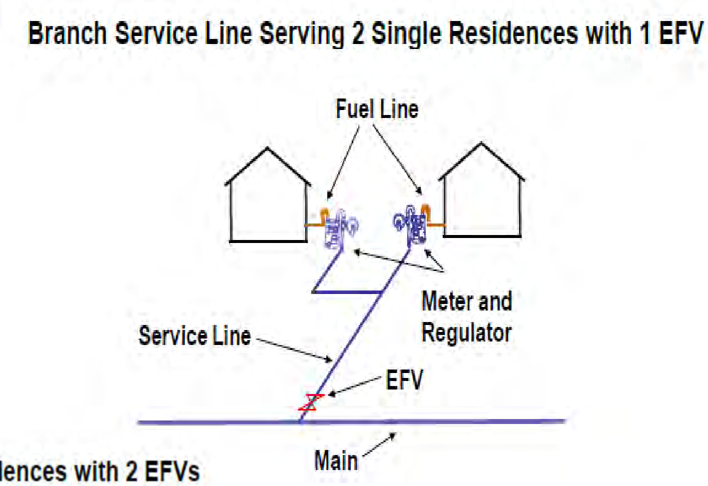
(continued on next page)

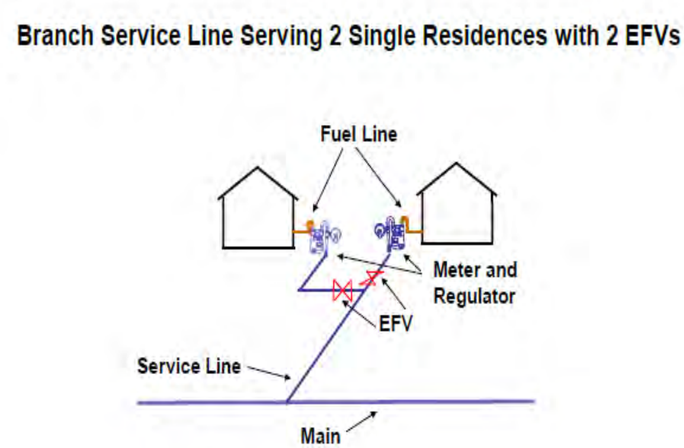
Reporting:

1) All EFVs installed throughout the calendar year and a total number of EFVs in the system must be reported on the PHMSA 7100 Annual Distribution Report.

<u>See below for example installation configurations.</u>







Division 9.23: Excess Flow Valve – Customer Right to Request *(Reference 192.383)*

EXCEPTION: This requirement does NOT apply to operators whose gas system does NOT operate at or above 10 psi throughout the year. For operators of master meter systems with less than 100 customers a notice may be continuously posted in a prominent location frequented by customers.

Existing service line customers who desire an EFV on service lines not exceeded 1,000 SCFH and who do not qualify for one of the exceptions listed in 9.22 of this Plan, may request an EFV be installed on their service line. If an eligible service line customer requests an EFV installation, an operator must install the EFV at a mutually agreeable date. The operator's rate-setter determines how and to whom the costs of the EFV installation are distributed.

Customer Notification Concerning EFV Installation:

NOTE: "Customers" include existing customers and customers who sign up for gas service at a location with an existing service line that does not contain an EFV.

1) Operators must notify customers of their right to request an EFV in the following manner.
   a) Must provide written or electronic notification to customers of their right to request the installation of an EFV. Electronic notification may include emails, web-site posting, and e-billing notices.
   b) The notification must include an explanation for the service line customer of the potential safety benefits that may be derived from installing an EFV. The explanation must include information that an EFV is designed to shut off the flow of gas automatically if the service line breaks.
   c) The notification must include a description of EFV installation and replacement costs. The notice must alert the customer that the costs for maintaining and replacing an EFV may later be incurred, and what those costs will be to the extent known.
   d) The notification must indicate that if a service line customer requests installation of an EFV and load does not exceed 1,000 SCFH and the conditions of the exceptions listed in Division 9.22 of this Plan are not present, the operator must install an EFV at a mutually agreeable date.

Evidence of Customer Notification:

1) A copy of the notice or notices currently in use must be available during PHMSA or State inspections.

(see next 4 pages for Customer Notification Template)

(insert name of utility company or company letter head)

DATE: (insert date here)

Note: This notification is being delivered to fulfill a requirement as part of a rulemaking passed down from the Pipeline and Hazardous Materials Association that takes effect on April 14, 2017.

Customer Notification of Excess Flow Valve (EFV) Installation

Dear Valued Customer,

You may request that [insert utility name] install an excess flow valve (EFV) on the gas line to your property. EFVs are mechanical shut-off devices that a utility can install in the gas pipe running from the gas main to the gas meter at your property (the "service line"). An EFV is designed to stop the gas flow if the service line is broken, for example, by an excavation accident. Stopping the gas flow from a broken service line significantly reduces the risk of natural gas fire, explosion, personal injury and/or property damage.

If you notify us that you want an EFV, we will contact you to set up a mutually agreeable date when we will install an EFV on your service line. [insert type of cost recovery text here – see below]

1. **Potential advantages & disadvantages of Excess Flow Valves (EFVs).**

   a. An EFV is designed to shut off the gas flow if the service line is severed between the gas main and the meter set.

   b. What an EFV won't do?

      - An EFV is NOT designed to close if a leak occurs beyond the gas meter on house piping or appliances. An EFV also may not close if the leak on the service line is small.

   c. Possibility of EFV activation (closure) if the customer adds load.

      - If you add, for example, more gas appliances, a pool heater, emergency generator, etc., the additional gas flow may cause the EFV to close.

2. **EFV Installation and Replacement Costs** (choose one of the following options (i-v))

   a. Installation Cost

      i. **No cost to customer.**

   There is no cost to you, the customer, to install the EFV.

      ii. **Customer pays actual installation cost, provided to customer on a case-by-case basis when EFV installation is requested. Notification describes a range of estimated costs.**

   You will be billed for the cost of installing the EFV. The average installation cost is typically [insert your approximate cost range], but the actual installation cost will depend on the difficulty of installation. We will inform you of the actual cost before you make the final decision that you want an EFV.

      iii. **Customer requesting EFV installation pays a fixed fee listed in the notification that may or may not cover the actual installation costs.**

   You will be billed [insert cost] to cover the cost of installing the EFV.

      iv. **Additional charge per month rate with or without an upfront payment.**

   {insert dollar amount] will be added to your monthly gas bill for the cost of installing the EFV.

      v. **Other installation cost recovery method not described above – insert your own language to describe.**

   b. Replacement Cost (choose one or more of the following options (i-iv))

      i. **No cost to customer.**

   If the EFV on your service line must be replaced, we will replace the EFV at no charge to you.

      ii. **Customer pays the actual cost of EFV replacement. Notification describes a range of potential replacement costs.**

   If the EFV on your service line must be replaced, you will be billed for the cost of replacing the EFV. Replacing an EFV can cost from [insert your approximate cost range], but the actual replacement cost will depend on the difficulty of replacement.

iii. **Customer requesting EFV installation pays a fixed fee if replacement is required. The cost listed in the notification may or may not cover the actual replacement costs.**

If the EFV on your service line must be replaced, you will be billed [insert replacement fee]

iv. **Other replacement cost recovery method not described above – insert your own language to describe.**

c. What might trigger a need to replace the EFV?

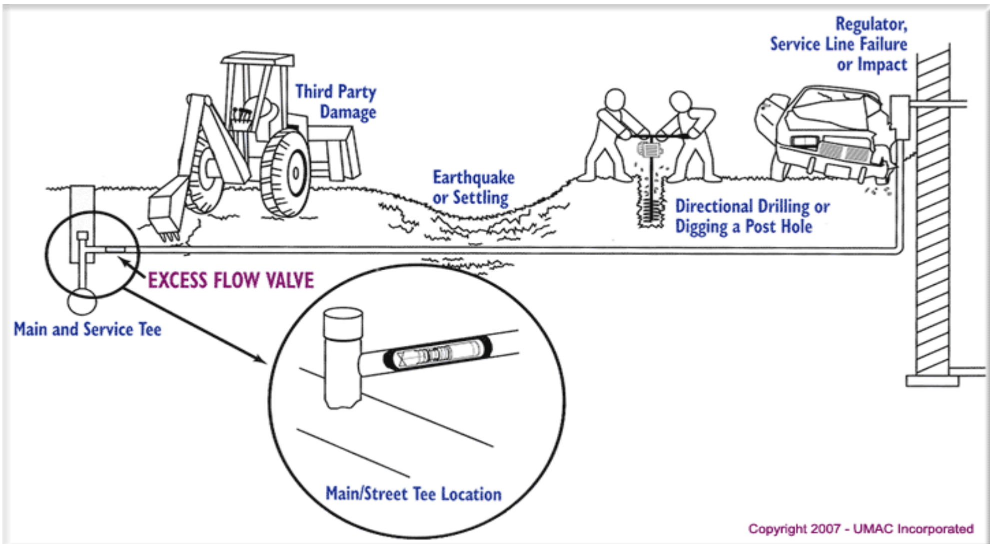
i. **Customer adds load:** EFV replacement may be necessary if you add additional gas appliances, such as a pool heater or emergency generator that exceeds the capacity of the EFV.
ii. **EFV fails closed/open:** EFV replacement may be necessary if the EFV malfunctions (sticks open or closed).
iii. **Probability of failure based on industry experience:** Industry experience is that EFVs rarely malfunction.

3. If a service-line customer requests EFV installation and the load does not exceed 1,000 SCFH and the conditions listed below are not present, the operator must install an EFV at a mutually agreeable date.

   a. The service line does not operate at a pressure of 10 psig or greater throughout the year;
   b. The operator has prior experience with contaminants in the gas stream that could interfere with the EFV's operation or cause loss of service to a customer;
   c. An EFV could interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or
   d. An EFV meeting the performance standards in § 192.381 is not commercially available to the operator

   IMPORTANT NOTE: EFVs cannot be installed on some service lines due to high gas flow, low pressure or other factors. If you request an EFV but your service line cannot accommodate an EFV, the (insert utility name) will inform you.

Diagram to illustrate an EFV:



Division 9.24: Manual Service Line Shut-off Valve (Curb Valve) Installation

(Reference 192.385)

Definition:

1) *Manual Service Line Shut-off Valve* – A curb valve or other manually operated valve located near the service line that is safely accessible to operator personnel or other personnel authorized by the operator to manually shut off gas flow to the service line, if needed.

Installation Requirements:

1) The operator must install either a manual service line shut-off valve or, if possible, based on sound engineering analysis and availability, an EFV for any new or replaced service line with installed meter capacity exceeding 1,000 SCFH.
2) See IAMU Procedure #3.6 – Install Excess Flow Valves or Curb Valve for installation procedures.

Installation Reference Chart:

Installed Meter Capacity	**Installation Requirements**
Less than or equal to 1,000 scfh	Excess Flow Valve (EFV)
Greater than 1,000 scfh	Excess Flow Valve (EFV) **OR** Curb Valve

Accessibility and Maintenance:

1) Manual service line shut-off valves installed for any new or replaced service line must be installed in such a way as to allow accessibility during emergencies. Manual service shut-off valves installed are subject to regularly scheduled maintenance not exceeding 5 years or 63 months.
2) See IAMU Procedure #3.6 – Install Excess Flow Valves or Curb Valve for maintenance procedures.

CITY OF BLOOMFIELD, IOWA

DIVISION TEN

Requirements for Corrosion Control

49 CFR Part 192 Subpart I

Division 10.1: Scope *(Reference 192.451)*

This Division prescribes minimum requirements for the protection of metallic pipelines from external, internal, and atmospheric corrosion.

Division 10.2: How Does This Apply to Converted Pipelines and Regulated Onshore Gathering Lines *(Reference 192.452)*

1) *Converted Pipelines* - Each pipeline that qualifies for use under 49 CFR Part 192 in accordance with Division 2.6 of this Plan must meet the requirements of the Division specifically applicable to pipelines installed before August 1, 1971, and all other applicable requirements within 1 year after the pipeline is readied for service. However, the requirements of the Division specifically applicable to pipelines installed after July 31, 1971, apply if the pipeline substantially meets those requirements before it is readied for service or it is a segment that is replaced, relocated or substantially altered.
2) *Regulated Onshore Gathering Lines* – Not applicable. Gathering pipelines as defined by 49 CFR Part 192.9 DO NOT exist for anyone using this Plan.

Additional Information:

1) If an operator chooses to convert an existing pipeline (i.e., propane to natural gas), the operator should review all corrosion control records or perform field testing to ensure that the pipeline being converted meets the corrosion control requirements of this Division within 12 months of the conversion.
2) Records and testing may include exposed pipe examinations, pipe to soil measurements and pipe coating inspections.
3) A record of the review process should be maintained for the life of the pipeline.

Division 10.3: General Information *(Reference 192.453)*

The corrosion control procedures required by 49 CFR Part 192.605(b)(2), including those for the design, installation, operation and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified in pipeline corrosion methods.

Desired Knowledge of Corrosion Control for Operating Personnel:

1) The operating personnel who are responsible for the design, installation, operation, or maintenance of corrosion control systems should have the knowledge and practical experience in the following, as it applies to their specific gas system and operator qualification:
    a) Cathodic protection systems (galvanic or impressed current)
    b) Pipeline coatings
    c) Survey methods and evaluation techniques
    d) Instruments used for surveys and evaluations
    e) Electrical isolation
    f) Stray currents

Division 10.4: External Corrosion Control – Buried or Submerged Pipelines Installed After July 31, 1971 *(Reference 192.455)*

Installation Requirements:

All pipelines installed after July 31, 1971 that are either buried or submerged must be protected against external corrosion including the following:

1) Must have an external protective coating meeting the requirements of Division 10.7 of this Plan.
2) Must have a cathodic protection system designed to protect the pipeline installed within 1 year after completion of installation according to requirements found in Division 10 of this Plan.
3) All electrically isolated metallic fittings installed after January 22, 2019, must be coated, cathodically protected, and maintained according to integrity management plans.

Installation Exceptions:

1) An operator does not need to comply with the installation requirements listed above, if the operator can demonstrate by testing, 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 installation, the operator must 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, and soil resistivity measurements at potential profile peak locations, to adequately evaluate the potential profile along the entire pipeline. If testing indicates that a corrosive condition exists, the pipeline must be cathodically protected as stated above in Installation Requirements.

NOTE: In general, all new pipelines will be coated and cathodically protected as stated in the Installation Requirements, as it is extremely costly and difficult to prove that a non-corrosive environment exists.

Additional Information:

1) For electrically isolated metallic fittings (couplings, valves, etc.) installed on plastic pipelines, an anode may be directly connected to the isolated fitting and then coated.
   a) The operator may choose to install a separate test lead and test station to allow for cathodic protection monitoring.
   b) Cathodic protection of the isolated fitting can also be accomplished by directly connecting the tracer wire (if connected to a cathodically protected steel main) to the fitting.

Division 10.5: External Corrosion Control – Buried or Submerged Pipelines Installed Before August 1, 1971 *(Reference 192.457)*

1) Except for buried piping at compressor, regulator, and measuring stations, each buried or submerged transmission line installed before August 1, 1971, that has an effective external coating must be cathodically protected along the entire area that is effectively coated.
2) Except for cast or ductile iron, each of the following buried or submerged pipelines installed before August 1, 1971, must be cathodically protected in accordance with this Division of this Plan in areas where active corrosion is found:
   a) Bare or ineffectively coated transmission lines.
   b) Bare or coated pipe at compressor, regulator, and measuring stations.
   c) Bare or coated distribution lines.

Additional Information:

Active Corrosion – is defined as continuing corrosion, which unless controlled, could result in a condition that this detrimental to public safety.

1) Bare or coated distribution pipelines, regulating, and measuring stations shall be cathodically protected in areas of active corrosion.
2) Active corrosion will be determined by the following:
   a) Electrical surveys.
   b) The study of corrosion and leak history records where an electrical survey is impractical.
   c) Leak detection surveys.
3) The use of electrical surveys to find areas of active corrosion will be considered impractical in the following situations:
   a) In areas of fluctuating stray DC currents, such as those caused by telluric current and electrical railway systems;
   b) Where the pipeline is more than 2 feet in from and generally parallel to the edge of a paved street or within wall-to-wall paved areas;
   c) Where pipelines are in a common ditch/trench with other metallic structures;
   d) Where the pipe is electrically discontinuous.
4) Continuing corrosion will be considered active corrosion if it occurs on the distribution system within the city limits and within 100 yards of a building intended for human occupancy, regulator stations, and at highway and railroad crossings.
   a) Pipelines with active corrosion must be cathodically protected, repaired, or replaced.

NOTE: In areas where electrical surveys cannot be conducted to determine corrosion, leakage surveys must be conducted on a more frequent basis determined by the operator and according to integrity management plans.

Division 10.6: External Corrosion Control – Examination of Buried Pipeline When Exposed *(Reference 192.459)*

NOTE: See IAMU Procedure #4.1 - Visual Inspection of Buried Pipe and Components When Exposed for specific details.

1) Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion must be inspected for evidence of external corrosion or if the coating is damaged or deteriorated. The inspection must be conducted circumferentially and longitudinally along the pipeline.
2) If external corrosion, coating damage, or coating deterioration is found, remedial action such as repairs or replacements must be taken.
3) Anytime the operator exposes pipe and damage or external corrosion is discovered, the operator must continue to expose additional pipe until the extent of the damage or external corrosion is determined.
4) If at any time the internal surface of the pipeline is exposed, an internal corrosion inspection must be conducted according to IAMU Procedure #4.10 - Visual Inspection for Internal Corrosion.

Additional Information:

1) All inspections of exposed pipe and components must be recorded and documented even if there is no evidence of external corrosion, coating damage, or deterioration.
2) Anytime pipe or components are exposed by potholing or hydro-excavation, a visual inspection must be conducted and documented.
   a) If access to the bottom portion of the exposed pipe or component is limited, consider the use of a mirror if applicable.
   b) A visual inspection must be conducted on all exposed pipe and components for each individual pothole even if there are multiple potholes on the same segment of pipe as each pothole is located on a different portion of the pipeline and conditions from one pothole to the next could vary greatly.
   c) Documentation of the visual inspection should be provided for each individual pothole location.
3) Although not required, it is recommended that if a casing pipe is exposed, a visual inspection may be conducted and documented to verify the current condition of the casing pipe.

Division 10.7: External Corrosion Control – Protective Coating *(Reference 192.461)*

NOTE: See the following procedures for specific details for installing and/or repairing protective coatings:

- **IAMU Procedure #4.16 - Pipe Surface Preparation for Coating Application**
- **IAMU Procedure #4.15 - Coating Application & Repair: Wrapped**

1) All external protective coatings, whether conductive or insulating, applied for external corrosion control must:
   a) Be applied on a properly prepared surface;
   b) Have sufficient adhesion to the metal surface t effectively resist under-film migration of moisture;
   c) Be sufficiently ductile to resist cracking;
   d) Have sufficient strength to resist damage due to handling and soil stress;
   e) Have properties compatible with any supplemental cathodic protection.
2) Each external protective coating which is an electrically insulating type must also have low moisture absorption and high electrical resistance.
3) All external protective coatings must be inspected prior to lowing the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired.
4) Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.
5) If coated pipe is installed by boring, driving, or other similar method, precautions must be taken to minimize damage to the coating during installation.

Division 10.8: External Corrosion Control – Cathodic Protection Criteria
(Reference 192.463)

1) Each cathodic protection system required by Division 10 of this Plan must provide a level of cathodic protection that complies with one or more of the applicable criteria listed in Appendix D of 49 CFR Part 192. If none of the listed criteria is applicable, the cathodic protection system must provide a level of cathodic protection at least equal to that provided by compliance with one or more of the listed criteria.
2) If amphoteric metals are included in a buried or submerged pipeline containing a metal of different anodic potential –
   a) The amphoteric metals must be electrically isolated from the remainder of the pipeline and cathodically protected; or
   b) The entire buried or submerged pipeline must be cathodically protected at a cathodic potential that meets the requirements of Appendix D of 49 CFR Part 192.
3) The amount of cathodic protection must be controlled so as not to damage the protective coating or the pipe.

Additional Information on Selected Criteria for use with This Plan:

1) The cathodic protection criteria selected for use with this Plan is the -0.85 volts criteria.
   a) Using this criterion, with protective current being applied, a voltage reading of at least -0.85 volts must be measured in order for the cathodic protection system to be considered adequate.
   b) This is a simple "go, no-go" type of monitoring of a cathodic protection system. If the meter reaches at least -0.85 volts, the operator verifies that the steel pipe segment is under sufficient cathodic protection. If not, remedial action must be taken promptly to correct the deficiency.
   c) Consideration should be given to IR drop potential when using the -0.85 criteria.
      i) IR drop potential is the difference between the voltage reading at the top of the pipe (below ground) and the voltage reading taken at the ground surface.

Division 10.9: External Corrosion Control – Monitoring *(Reference 192.465)*

Cathodically Protected Pipelines:

1) Each pipeline that is under cathodic protection must be tested at least once each calendar year, not to exceed 15 months, to determine that cathodic protection levels meet the selected -0.85 volts criteria, by taking pipe-to-soil potential measurements (structure to electrolyte potential) at specific locations.
2) Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar, but with intervals not exceeding 2 ½ months, to ensure that it is operating.
3) 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 ½ months. Each other interference bond must be checked at least once each calendar year, not to exceed 15 months.
4) Prompt remedial action must be taken to correct any deficiencies indicated by the monitoring.
   a) Remedial action must begin within 90 days of the date of the discovery, and be completed before the next scheduled survey.
   b) See IAMU Procedure #4.3 - Determine Appropriate Remedial Measures for Corrosion Control and Notification of Proper Personnel for additional details.

Separately Protected Mains & Service Lines:

Separately protected mains, not in excess of 100 feet, and separately protected service lines may be surveyed on a sampling basis.

1) At least 10% of these separately protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10% checked each subsequent year, so that the entire system is tested over each 10-year period.

Unprotected Pipelines:

1) After the initial evaluations required by Division 10.4 & 10.5 of this Plan, each operator must reevaluate unprotected pipelines at once every 3 years, not to exceed 39 months, and cathodically protect them according to Division 10 of this Plan in areas where active corrosion is found. The operator must determine the areas of active corrosion by electrical survey. However, on distribution lines and where 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.

NOTE: See IAMU Procedure #4.0 - Measure Structure to Electrolyte Potential and/or IAMU Procedure #4.4 - Inspect Rectifier and Obtain Readings for procedures specific to the type of cathodic protection system.

Division 10.10: External Corrosion Control – Electrical Isolation *(Reference 192.467)*

1) 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.
2) 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.
3) 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 pipe inside the casing (carrier pipe).
4) Inspection and electrical tests must be made to ensure that electrical isolation is adequate.
5) An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.
6) Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.

Additional Information:

1) Below is a list of examples of where electrical isolation (insulators) may be installed, inspected, and/or tested:
   a) Take points and/or town boarder stations (change of ownership locations) to ensure electrical isolation from supplier unless protected as a single unit.
   b) Inlet and outlet piping of regulator and/or measuring stations.
   c) All service line termination points (meter set locations).
   d) Casings should be electrically isolated from the carrier pipe.
   e) Installed on a main as to isolate one cathodic protection zone from another.
2) Installation and testing for electrical isolation can be accomplished by multiple methods. See IAMU Procedure #4.8 - Inspect or Test Cathodic Protection Electrical Isolation Devices and IAMU Procedure #4.9 - Install Cathodic Protection Electrical Isolation Devices for specific details.

Division 10.11: External Corrosion Control – Test Stations *(Reference 192.469)*

Each pipeline under cathodic protection must have sufficient test stations or other contact points for electrical measurement to determine the adequacy of the cathodic protection system.

Additional Information:

1) Any metallic contact point that is electrically continuous with the structure being tested, such as the following locations may be used as a cathodic protection test point:
   a) Regulator stations
   b) Service risers (can take read off of tracer wire if tied to steel main or steel riser)
   c) Valves
   d) Blow-downs
2) Test stations may be installed in the following locations with no direct access to the structure:
   a) Casings
   b) Insulating joints in mains
   c) Road or waterway crossings
   d) Foreign metallic structure crossings
3) Enough testing points should be selected and/or installed for testing so that monitoring survey results verify the adequacy of the entire system.
   a) Test points/stations should be spread evenly throughout the system.
   b) Test points/stations should be numerous enough so that no portion of the system is left exempt from monitoring.

Division 10.12: External Corrosion Control – Test Leads *(Reference 192.471)*

1) Each test lead wire must be installed so that it remains mechanically secure and electrically conductive.
2) Each test lead wire must be installed as to minimize stress concentration on the pipe.
3) All test lead wires and connections to pipelines must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

Additional Information:

1) Thermite (exothermic) welding using copper oxide and aluminum powder may be used as a method of connection on steel pipe. It is recommended that the thermite welding charge be limited to a 15-gram cartridge.
    a) For specific thermite welding procedures, see IAMU Procedure #4.7 - Installation of Exothermic Electrical Connections.
2) Mechanical connections that remain secure and electrically conductive may be used.
    a) For details on mechanical connections see IAMU Procedure #4.6 - Installation and Maintenance of Mechanical Electrical Connections.
3) Test lead wires that terminate inside a test station, should be permanently marked or identified to aid in completing monitoring surveys.
4) All test lead wires should be installed with slack and not exposed to excessive heat.
5) If test lead wires are damaged or become disconnected from the pipeline, repairs should be made.

Division 10.13: External Corrosion Control – Interference Currents *(Reference 192.473)*

1) Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effect of such currents.
2) Each impressed current type cathodic protection system or galvanic anode system must be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures.

Additional Information:

1) If stray currents are discovered during cathodic protection surveys, the following mitigation techniques may be used.
   a) Auxiliary cathodic protection, either impressed or galvanic, may be utilized to compensate the too positive potential around the current discharge region.
   b) An interference cell, normally a band of sacrificial anodes, may be installed as a stray current discharging point.
   c) Sacrificial anodes may be installed on both interfering and interfered structures to allow safe discharging of stray currents.
   d) Relocation of interfering anodes.
   e) Shielding and/or recoating of the pipeline receiving the stray current to limit the stray current magnitude.
   f) Design and install an electrical resistance bond to allow the return of stray current safely.
2) For stray current remediation, it may be necessary to contact NACE certified corrosion control personnel to determine the best course of action to eliminate or reduce the stray current.

Division 10.14: Internal Corrosion Control – General *(Reference 192.475)*

1) Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.
2) Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion.
3) If internal corrosion is found –
   a) The adjacent pipe must be investigated to determine the extent of the internal corrosion;
   b) Replacement must be made to the extent required by this Division of this Plan
   c) Steps must be taken to minimize the internal corrosion.
4) Gas containing more than 0.25 grain of hydrogen sulfide per 100 cubic feet at standard conditions may not be stored in pipe-type or bottle-type holders.

Additional Information:

1) Simply stated, anytime the operator has access to the internal surface of pipe or component of a metallic pipeline, it must be visually inspected for internal corrosion.
2) Internal surface oxidation (rust) is not considered internal corrosion for the purposes of this Plan.
   a) Deterioration, metal loss or pitting must be discovered and confirmed to be considered internal corrosion.
3) See IAMU Procedure #4.10 - Visual Inspection for Internal Corrosion and IAMU Procedure #4.13 - Measure Internal Corrosion for specific details.

Division 10.15: Internal Corrosion Control – Design and Construction of Transmission Line *(Reference 192.476)*

Design & Construction:

1) Except as provided in "exceptions to applicability" of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must have features incorporated into its design and construction to reduce the risk of internal corrosion. At a minimum, unless it is impracticable or unnecessary to do so, each new transmission line or replacement of line pipe, valve, fitting, or other line component in a transmission line must:
   a) Be configured to reduce the risk that liquids will collect in the line;
   b) Have effective liquid removal features whenever the configuration would allow liquids to collect; and
   c) Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion.

Exceptions to Applicability:

1) The design and construction requirements listed above, do not apply to the following:
   a) Offshore pipelines
   b) Pipelines and components installed or replaced before May 23, 2007.

Change to Existing Transmission Line:

1) When an operator changes the configuration of a transmission line, the operator must evaluate the impact of the change on internal corrosion risk to the downstream portion of an existing onshore transmission line and provide for removal of liquids and monitoring of internal corrosion as appropriate.

Records:

1) An operator must maintain records demonstrating compliance with this section. Provided the records show why incorporating design features addressing the "design and construction" requirements listed above is impracticable or unnecessary, an operator may fulfill this requirement through written procedures supported by as-built drawings or other construction records.

Additional Information:

1) It is recommended that an operator seek out a licensed engineer to determine the internal corrosion control methods incorporated into the design and construction of new or replaced transmission pipelines to ensure that the requirements of this Division are fulfilled.

Division 10.16: Internal Corrosion Control – Monitoring *(Reference 192.477)*

If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with intervals not exceeding 7 ½ months.

Additional Information:

1) If it has been determined that corrosive gas is being transported, the following devices may be installed to monitor the effectiveness of the internal corrosion control program:
    a) Hydrogen probes
    b) Corrosion probes
    c) Corrosion coupons
    d) Test spools
    e) Non-destructive testing equipment that is capable of measuring wall thickness may be utilized.
2) If internal corrosion monitoring is required, a written procedure should be developed and inserted into this Plan.

Division 10.17: Atmospheric Corrosion Control - General *(Reference 192.479)*

Definition:

Atmospheric corrosion – is defined as corrosion that causes deterioration or pitting of the pipe surface resulting from a reaction with the atmospheric environment.

Requirements:

1) Except for "exceptions" listed below, all pipelines or portions or pipelines exposed to the atmosphere must be cleaned and coated.
2) All material used for coating applications must be suitable for the prevention of atmospheric corrosion.

Exceptions:

1) Except for portions of pipelines located at soil-to-air interfaces, the operator does not need to protect from atmospheric corrosion any pipeline for which it has been demonstrated by testing, investigation, or experience appropriate to the environment, that corrosion will –
   a) Only be light surface oxide; or
   b) Not affect the safe operation of the pipeline before the next scheduled inspection.

Additional Information:

1) During the design and before installation of above ground facilities, special consideration should be given to the selected location. The following should be considered prior to installation:
   a) An installation where condensation may accumulate or remain moist due to high flow demand or large pressure cut.
   b) An area where chemicals that cause or accelerate corrosion might be blown by the wind or come in direct contact may be expected.
   c) An agricultural area where animal waste may accumulate.
   d) An area prone to flooding or snow accumulation.
2) Unless demonstrated by testing, investigation, or experience all above ground facilities should be painted using a paint that prevents corrosion.
3) Special attention should be given where pipe transitions from below ground to above ground (soil-to-air interface). Generally, this area is coated with a type of corrosion control wrap or epoxy coating that is suitable for use and less likely to be damaged.

Division 10.18: Atmospheric Corrosion Control - Monitoring *(Reference 192.481)*

Definition:

Atmospheric corrosion – is defined as corrosion that causes deterioration or pitting of the pipe surface resulting from a reaction with the atmospheric environment.

Requirements:

1) Each pipeline or portion of a pipeline that is exposed to the atmosphere, must be inspected for evidence of atmospheric corrosion as follows:

Pipeline Type:	Frequency of Inspection:
Service Lines	At least once every 5 calendar years, not to exceed 63 months, except as stated in "Exceptions" listed below.
All other locations	At least once every 3 calendar years, not to exceed 39 months

"All other locations" include but are not limited to; hairpin valves, blow-down valves, regulator stations (DRS & TBS), bridge hangs, and separate telemetering or recording locations.

NOTE: For farm tap installations that contain an above ground hairpin first cut regulator and relief valve, this portion of the pipeline will be considered part of a service line and require a 5-year inspection interval.

2) During inspections, special attention must be given to soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.
3) If atmospheric corrosion is found during an inspection, protection must be provided against corrosion as required by Division 10.17 of this Plan.

Exceptions:

1) If atmospheric corrosion is found on a service line during the most recent inspection, then the next inspection of that specific portion of pipeline must be conducted within 3 calendar years, not to exceed 39 months.

Additional Information:

1) If pipe being inspected for atmospheric corrosion is being supported by pipe supports, pipe hangers, or other means, the supporting device should be moved to allow for the inspection of the supported area.
2) For specific details on atmospheric corrosion monitoring, see IAMU Procedure #4.11 - Visual Inspection for Atmospheric Corrosion and IAMU Procedure #4.14 - Measure Atmospheric Corrosion.

Division 10.19: Corrosion Control Remedial Measures - General *(Reference 192.483)*

1) Each segment of metallic pipe that replaces existing 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 Division 10.7 of this Plan.
2) Each segment of metallic pipe that replaces existing pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected in accordance with this Division of this Plan.
3) Except for cast iron or ductile iron pipe, each segment of buried or submerged pipe that is required to be repaired because of external corrosion must be cathodically protected in accordance with this Division of this Plan.

Additional Information:

1) Cathodic protection must be installed and maintained on all facilities that are scheduled for replacement until the pipeline has been replaced or removed.

Division 10.20: Corrosion Control Remedial Measures – Transmission Lines

(Reference 192.485)

General Corrosion Remedial Measures:

1) Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this section.
2) Each segment of transmission line pipe with general corrosion found resulting with a remaining wall thickness less than that required for the MAOP of the pipeline, must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness.
3) Corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

Localized Corrosion Pitting:

1) Each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.

Additional Information:

1) If general or localized corrosion is discovered, the strength of pipe based on actual remaining wall thickness may be determined by procedures found in ASME/ANSI B31G or PRCI PR 3-805 (R-STRENG).
2) If corrosion is discovered that disqualifies the pipeline for use at the current MAOP, or if the MAOP cannot be reduced to a safe pressure, the pipeline must be repaired or replaced.
3) See IAMU Procedure #4.2 - Measure External Corrosion for specific details on how to determine metal loss due to corrosion.

Division 10.21: Corrosion Control Remedial Measures – Distribution Lines Other Than Cast Iron or Ductile Iron *(Reference 192.487)*

General Corrosion Remedial Measures:

1) Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this section.
2) Except for cast or ductile iron pipe, each segment of generally corroded distribution pipeline with a remaining wall thickness less than that required for the MAOP of the pipeline, or a remaining wall thickness less than 30% of the nominal wall thickness, must be replaced.
3) Corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

Localized Corrosion Pitting:

1) Except for cast or ductile iron pipe, each segment of distribution pipeline with localized corrosion pitting to a degree where leakage might result must be repaired or replaced.

Additional Information:

1) Extensive corrosion is defined as any metal loss or pitting, that results in a loss of 70% or more of the wall thickness. If the remaining wall thickness is less than 30% of the original wall thickness, the pipe must be repaired or replaced.
   a) If metal loss or pitting is discovered, the depth of the metal loss or pit should be determined by using a pit gauge or caliper. Once the depth is measured, compare to the original wall thickness and determine the % of wall thickness that has been lost due to corrosion.
2) If corrosion is found that is not greater than or equal to 70% of wall loss and repairs and replacements are not necessary, the area must be at a minimum cleaned and properly coated. Consideration should also be given to the following:
   a) Installing an anode for additional cathodic protection.
   b) Examining the history of leak and repair records for facilities located in the general area.
      i) If leak and repair records show a pattern of leaks being repaired, replacement of the pipe should be considered.
3) See IAMU Procedure #4.2 - Measure External Corrosion for specific details on how to determine metal loss due to corrosion.

Division 10.22: Corrosion Control Remedial Measures – Cast Iron or Ductile Iron Pipelines *(Reference 192.489)*

1) *General graphitization* – Each segment of cast or ductile iron pipe on which general graphitization is found to a degree where a fracture or any leakage might result, must be replaced.
2) *Localized graphitization* – Each segment of cast or ductile iron pipe on which localized graphitization is found to a degree where any leakage might result, must be repaired or replaced, or sealed by internal sealing methods adequate to prevent or arrest any leakage.

Division 10.23: Direct Assessment *(Reference 192.490)*

NOTE: Only applies to gas transmission pipelines that contain a covered segment or identified site and require a transmission integrity management plan.

Definition:

Direct Assessment – As defined by 49 CFR Part 192.903, is an integrity assessment method that utilizes a process to evaluate certain threats (external, internal and stress corrosion) to a covered pipeline segment's integrity. The process includes the gathering and integration of risk factor data, indirect examination analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.

Requirements:

1) Each operator that uses direct assessment methods on an onshore transmission line made primarily of steel or iron to evaluate the effects of a threat in the first column must carry out the direct assessment according to the standard listed in the second column. These standards do not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process.

Threat	Standard
External corrosion	192.925
Internal corrosion in pipelines that transport dry gas	192.927
Stress corrosion cracking	192.929

Division 10.24: Corrosion Control Records *(Reference 192.491)*

1) Records or maps must be maintained to show the location of cathodically protected piping and facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system.
   a) 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.
2) Each record or map listed above, must be retained for as long as the pipeline remains in service.
3) Records of each test, survey, or inspection required by Division 10 of this Plan, must be maintained 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 a minimum of 5 years with the following exceptions:
   a) Records related to Divisions 10.9 and 10.14 must be kept for the life of the pipeline.
   b) Operators must retain records of the two most recent atmospheric corrosion inspections for each service line that is being inspected under the 5-year interval.

Additional Information:

1) Documentation and record retention requirements for each corrosion control test, survey, and inspection can be found for each specific procedure found in Part 4 of Written Procedures.

Division 10.25: In-line Inspection of Pipelines *(Reference 192.493)*

NOTE: This only applies to transmission pipelines that were constructed with launchers and receivers capable of conducting in-line inspections.

1) When conducting in-line inspections of pipelines, an operator must comply with API STD 1163, ANSI/ASNT ILI-PQ, and NACE SP0102. Assessments may be conducted using tethered or remotely controlled tools, not explicitly discussed in NACE SP0102, provided they comply the sections of NACE SP0102 that are applicable.

Additional Information:

1) If at any time a new transmission line is constructed or an existing transmission line is altered to accommodate in-line inspections, a procedure should be generated according to the above requirements and inserted into this Plan.

CITY OF BLOOMFIELD, IOWA

DIVISION ELEVEN

Test Requirements

49 CFR Part 192 Subpart J

Division 11.1: Scope *(Reference 192.501)*

This Division prescribes the minimum leak-test and strength test (pressure testing) requirements for pipelines.

Division 11.2: General Requirements *(Reference 192.503)*

NOTE: See Part Five – Pressure Testing of O&M Written Procedures for specific pressure testing requirements for pipelines with an MAOP less than 100 psi and with an MAOP greater than or equal to 100 psi.

1) No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated, replaced, or repaired until the following conditions have been met:
   a) It has been tested in accordance with this Division and with Division 13.12 to substantiate the maximum allowable operating pressure and each potentially hazardous leak has been located and eliminated.
      i) The test medium used during the pressure test must be liquid, air, natural gas, or inert gas that is –
         (1) Compatible with the material of which the pipeline is constructed;
         (2) Relatively free of sedimentary materials; and
         (3) Except for natural gas, nonflammable.
      ii) Except as provided in paragraph (1) of Division 11.3, if air, natural gas, or inert gas is used as the test medium, the following maximum hoop stress limitations apply:

Class Location	Maximum hoop stress allowed as % of SMYS	
	Natural gas	Air or inert gas
1	80	80
2	30	75
3	30	50
4	30	40

      iii) Each joint used to tie int a test segment of pipeline is excepted from the specific test requirements of this Division, but each non-welded joint must be leak tested at not less than its operating pressure.
      iv) If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required, if the manufacturer of the component certifies that:
         (1) The component was tested to at least the pressure required for the pipeline to which it is being added;
         (2) The component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added; or
         (3) The component carries a pressure ratting established through applicable ASME/ANSI, Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS) specifications, or by unit strength calculations as described in Division 5.2 of this Plan.

Division 11.3: Strength Test Requirements for Steel Pipeline to Operate at a Hoop Stress of 30% or More of SMYS *(Reference 192.505)*

1) Except for service lines, each segment of steel pipeline that is to operate at a hoop stress of 30% or more of SMYS must be strength tested in accordance with this Division to substantiate the proposed MAOP. In addition, in a Class 1 or Class 2 location, if there is a building intended for human occupancy within 300 feet of a pipeline, a hydrostatic test must be conducted to a test pressure of at least 125% of MAOP on that segment of the pipeline within 300 feet of such a building, but in no event may the test section be less than 600 feet unless the length of the newly installed or relocated pipe is less than 600 feet. However, if the buildings are evacuated while the hoop stress exceeds 50% of SMYS, air or inert gas may be used as the test medium.
2) In a Class 1 or Class 2 location, each compressor station, regulator station, and measuring station, must be tested to at least Class 3 location test requirements.
3) Except as provided in paragraph (2) of this Division, the strength test must be conducted by maintaining the pressure at or above the test pressure for at least 8 hours.
4) For fabricated short sections of pipe, for which a post installation test is impractical, a preinstallation strength test must be conducted by maintaining the pressure at or above the test pressure for at least 4 hours.

Additional Information:

1) If a single pipeline component (not pipe) is the only item being installed or replaced, a pressure test does NOT have to be completed if the component being installed has a valid ASME or MSS specification pressure rating equal to or greater than the MAOP of the pipeline to which it is attached.

Division 11.4: Transmission Lines: Spike Hydrostatic Pressure Test *(Reference 192.506)*

NOTE: This requirement is for transmission pipelines **ONLY**. Specific written procedures are **NOT** included in the Written Procedures section of this Plan. If at any time, procedures for this purpose are needed, it is recommended that an engineer is contracted to develop pressure test procedures specific to the pipeline being installed and the requirements listed below.

1) *Spike Test Requirements* - Whenever a segment of steel transmission pipeline is operated at a hoop stress level of 30% or more of SMYS is spike tested, the spike hydrostatic pressure test must be conducted in accordance with the following;
   a) The test must be conducted using water as the test medium.
   b) The baseline test pressure must be as specified in the applicable paragraphs of 192.619(a)(2) or 192.620(a)(2), whichever applies.
   c) The test must be conducted by maintaining a pressure at or above the baseline test pressure for at least 8 hours as specified in Division 11.3 of this Plan.
   d) After the test pressure stabilizes at the baseline pressure and within the first 2 hours of the 8-hour test interval, the hydrostatic pressure must be raised (spiked) to a minimum of the lesser of 1.5 times MAOP or 100% SMYS. The spike hydrostatic pressure test must be held for at least 15 minutes after the spike test pressure stabilizes.
2) *Other Technology or Other Technical Evaluation Process* – Operators may use other technology or another process supported by a documented engineering analysis for establishing a spike hydrostatic pressure test or equivalent. Operators must notify PHMSA 90 days in advance of the assessment or reassessment requirements of this paragraph. The notification must be made in accordance with Division 2.8 of this Plan and include the following information:
   a) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments;
   b) Procedures and processes to conduct tests, examinations, assessments, perform evaluations, analyze defects, and remediate defects discovered;
   c) Data requirements, including original design, maintenance and operating history, anomaly or flaw characterization;
   d) Assessment techniques and acceptance criteria;
   e) Remediation methods for assessment findings;
   f) Spike hydrostatic pressure test monitoring and acceptance procedures, if used;
   g) Procedures for remaining crack growth analysis and pipeline segment life analysis for the time interval for additional assessments, as required; and
   h) Evidence of a review of all procedures and assessments by a qualified technical subject matter expert.

Division 11.5: Test Requirements for Pipelines to Operate at a Hoop Stress Less Than 30% SMYS and at or Above 100 psi *(Reference 192.507)*

NOTE: See IAMU Procedure #5.2 - Pressure Test: MAOP Greater Than or Equal to 100 psi for specific pressure testing procedures that meet the following requirements:

1) Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a pressure equal to or greater than 100 psi and at a hoop stress less than 30% SMYS must be tested in accordance with the following:
   a) A test procedure must be used 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% or more of SMYS and natural gas, inert gas, or air is the test medium being used –
      i) A leak test must be made at a pressure between 100 psi and the pressure required to produce a hoop stress of 20% or more of SMYS; or
      ii) The line must be walked to check for leaks while the hoop stress is held at approximately 20% of SMYS.
   c) The pressure must be maintained at or above the test pressure for at least 1 hour.
   d) For fabricated units and short sections of pipe, for which a post installation test is impractical, a preinstallation hydrostatic pressure test must be conducted in accordance with the requirements of this Division.

Division 11.6: Test Requirements for Pipelines to Operate Below 100 psi
(Reference 192.509)

NOTE: See IAMU Procedure #5.1 - Pressure Test: MAOP Less Than 100 psi for specific pressure testing procedures that meet the following requirements.

1) Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a pressure less than 100 psi must be leak tested in accordance with the following:
   a) The test procedure used must ensure the discovery of all potentially hazardous leaks in the segment being tested.
   b) Each main that is to be operated at less than 1 psi must be tested to at least 10 psi.
   c) Each main that is to be operated at or above 1 psi must be tested to at least 90 psi.

Division 11.7: Test Requirements for Service Lines *(Reference 192.511)*

NOTE: See IAMU Procedure #5.1 - Pressure Test: MAOP Less Than 100 psi for specific pressure testing procedures that meet the following requirements.

1) Each segment of a service line (other than plastic) must be leak tested in accordance with this Division before being placed into service. If feasible, the service line connection to the main (tapping tee) must be included in the test. If not feasible, it must be leak tested at the operating pressure when placed into service.
2) Each segment of a service line (other than plastic) intended to be operated at a pressure of at least 1 psi but not more than 40 psi, must be pressure tested to no less than 50 psi.
3) Each segment of a service line (other than plastic) intended to be operated at pressures greater than 40 psi, must be tested to no less than 90 psi, except that each segment of a steel service line stressed to 20% or more of SMYS must be tested in accordance with Division 11.5 of this Plan.

Additional Information:

1) The minimum required pressure for any pressure test according to written procedures found in this Plan, is 90 psi, regardless of what is stated above in paragraph (2).

Division 11.8: Test Requirements for Plastic Pipelines *(Reference 192.513)*

NOTE: See IAMU Procedure #5.1 - Pressure Test: MAOP Less Than 100 psi for specific pressure testing procedures that meet the following requirements.

1) Each segment of plastic pipeline must be tested in accordance with this Division.
2) The test procedure must ensure discovery of all potentially hazardous leaks in the segment being tested.
3) The test pressure must be at least 150% (1.5 times) of the maximum operating pressure or 50 psi, whichever is greater. However, the maximum test pressure may not be more than 2.5 times the pressure determined under Division 4.3 of this Plan at a temperature not less than the temperature during the test.
4) During the test, the temperature of thermoplastic material may not be more than 100°F, or the temperature at which the material's long-term hydrostatic strength has been determined under the listed specification, whichever is greater.

Additional Information:

2) The minimum required pressure for any pressure test according to written procedures found in this Plan, is 90 psi, regardless of what is stated above in paragraph (3) above.
3) To ensure that temperature limitations are not exceeded for plastic pipe, it may be necessary to keep the pipeline out of direct sunlight by placing it in the ditch in the shade, partially backfilling the pipeline (leaving all joints exposed), or performing the test during a cooler part of the day (early morning or late afternoon).

Division 11.9: Environmental Protection and Safety Requirements *(Reference 192.515)*

1) While conducting tests according to this Division, all operators shall ensure that every reasonable precaution is taken to protects employees and the general public during testing. Whenever the hoop stress of segment of the pipeline being tested will exceed 50% SMYS, the operator must take all practicable steps to keep persons not working on the testing operation outside of the testing area until the pressure is reduced to or below the proposed MAOP of the pipeline.
2) The operator must ensure that the test medium is disposed of in a manner that will minimize damage to the environment.

Additional Safety Information & Considerations:

1) All steps must be taken to prevent accidental ignition prior to, during, and after the testing is complete.
2) Fire extinguishers and combustible gas indicators should be readily available and located upwind.
3) Assess the area, are there any electrical conductors or additional utilities in the general testing vicinity?
4) If conducting the test in heavily populated area, consideration should be given to restricting access to the area to those not involved in the test by the use of temporary barricades, caution tape, or fencing off the area.
5) Consideration should be given to reviewing the testing procedure step-by-step with all personnel involved in the testing prior to conducting the test.
6) If using testing plugs or end caps, inspect them prior to and during the testing to ensure that they are securely connected and leak tight.
7) If a hydrostatic pressure test is conducted, it is recommended that a detailed plan be developed by an engineer taking consideration for the following:
   a) Filling and dewatering the pipeline
   b) Finding appropriate water sources.
   c) Erosion control methods used during discharge.
   d) Ensure that there is no contamination of surface waters (ponds, lakes, rivers, streams) during discharge.
   e) Scheduling and selecting an appropriate location for blowing down the line in order to reduce disturbances to the public.

Division 11.10: Records *(Reference 192.517)*

1) A record must be made and retained for the life of the pipeline of each test that is performed according to this Division.
2) The record must contain at least the following information:
   a) The operator's name, the name of the operator's employee responsible for make the test, and if applicable, the name of any test company (third party contractor) used.
   b) Test medium used.
   c) Test pressure.
   d) Test duration.
   e) Pressure recording charts, or other record of pressure readings (initial and final pressure).
   f) Elevation variations, whenever significant for the particular test.
   g) If any leaks and failures were found and their disposition.

Additional Information:

1) The test record may also include the following:
   a) Start and stop time of the test.
   b) Type, size and print line (manufacturing data) of all pipe and components.
   c) Pipeline length, in feet, of segment being tested.
   d) The types of joining methods used (electrofusion, butt fusion, compression couplings, etc.).
   e) Generate a detailed map, noting location of joints, couplings, valves, EFVs, etc.
   f) Calculated MAOP of pipeline tested.
2) Consideration should be given to obtaining photographic evidence.
   a) Pictures may be taken to capture print line information or to provide additional visual aid of the installation.
3) The Pipeline Installation Test Report or other approved company document may be used to capture and retain the required information.

CITY OF BLOOMFIELD, IOWA

DIVISION TWELVE

Uprating

49 CFR Part 192 Subpart K

Division 12.1: Scope *(Reference 192.551)*

This Division details the minimum requirements for increasing the maximum allowable operating pressure (MAOP uprating) for pipelines.

Division 12.2: General Requirements *(Reference 192.553)*

NOTE: See IAMU Procedure #6.1 - Uprate a Pipeline for specific procedures detailing how to meet the following requirements.

1) *Pressure increases* – Whenever the requirements of this Division state that an increase in operating pressure be made in increments, it must be done so gradually, at a rate that can be controlled, and in accordance with the following:
   a) At the end of each incremental pressure increase, the pressure must be held constant while the entire segment of the affected pipeline is checked for leaks.
   b) Each leak that is detected, must be repaired before a further pressure increase is made, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous.
2) *Records* – Each operator who uprates a segment of segment of pipeline shall retain for the life of the segment a record of each investigation required by this Division, of all work performed, and of each pressure test conducted, in connection with the uprating.
3) *Written Plans* – Each operator who uprates a segment of pipeline shall establish a written procedure that will ensure that each applicable requirement of the Division is complied with.
4) *Limitation on Increase in MAOP* – Except as provided in Division 12.3 of this Plan, a new MAOP established according to this Division, may not exceed the maximum that would be allowed under §192.619 and §192.621 for a new segment of pipeline constructed of the same materials in the same location. However, when uprating a steel pipeline, if any variable necessary to determine the design pressure under the design formula (Division 4.2) is unknown, the MAOP may be increased as provided in §192.619(a)(1).

Additional Information

1) If it is determined that an uprating is necessary to fulfill capacity or pressure requirements of a distribution system, a licensed engineer or subject matter expert should be contracted to generate the required written plan.
   a) Once a written plan has been generated, it should be submitted to the Iowa Utilities Board for approval before the uprating process begins.

Division 12.3: Uprating to a Pressure That Will Produce a Hoop Stress of 30% or More of SMYS in Steel Pipelines *(Reference 192.555)*

NOTE: This Plan does NOT provide a written procedure for this specific type of uprating. If this type of uprating is required, a written procedure meeting the following requirements must be developed and incorporated into this Plan at that time.

1) Unless the requirements of this section have been met, no person may subject any segment of steel pipeline to an operating pressure that will produce a hoop stress of 30% or more of SMYS and that is above the established MAOP.
2) Before increasing operating pressure above the previously established MAOP, the operator shall –
   a) Review the design, operating, and maintenance history and previous testing of the segment of pipeline and determine whether the proposed increase is safe and consistent with the requirements of this Division; and
   b) Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for the safe operation at the increased pressure.
3) After complying with paragraph (2) of this Division, an operator may increase the MAOP of a segment of pipeline constructed before September 12, 1970, to the highest pressure that is permitted under §192.619, using as test pressure the highest pressure to which the segment of pipeline has been previously subjected (either in strength test or in actual operation).
4) After complying with paragraph (2) of this Division, an operator that does not qualify under paragraph (3) of this Division may increase the previously established MAOP if at least one of the following requirements is met:
   a) The segment of pipeline is successfully tested in accordance with the requirements of this Plan for a new line of the same material in the same location.
   b) An increased MAOP may be established for a segment of pipeline in a Class 1 location if the line has not previously been tested, and if –
      i) It is impractical to test it in accordance with the requirements of this Plan;
      ii) The new MAOP does not exceed 80% of that allowed for a new line of the same design in the same location; and
      iii) The operator determines that the new MAOP is consistent with the condition of the segment of pipeline and the design requirements of this Plan.
5) Where a segment of pipeline is uprated in accordance with paragraph (3) or (4)(b) of this Division, the increase in pressure must be made in increments that are equal to –
   a) 10% of the pressure before the uprating; or
   b) 25% of the total pressure increase, whichever produces the fewer number of increments.

Division 12.4: Uprating to a Pressure That Will Produce a Hoop Stress Less Than 30% of SMYS – Plastic, Cast Iron, & Ductile Iron Pipeline *(Reference 192.557)*

NOTE: See IAMU Procedure #6.1 - Uprate a Pipeline for specific procedures detailing how to meet the following requirements for plastic pipelines. Cast iron and ductile iron pipelines are NOT included in the specific IAMU procedure.

1) Unless the requirements of this Division have been met, no person may subject –
   a) A segment of steel pipeline to an operating pressure that will produce a hoop stress less than 30% of SMYS and that is above the previously established MAOP; or
   b) A plastic, cast iron, or ductile iron pipeline segment to an operating pressure that is above the previously established MAOP.
2) Before increasing operating pressure above the previously established MAOP, the operator shall –
   a) Review the design, operating, and maintenance history of the segment of pipeline;
   b) Make a leakage survey and repair any leaks that are found, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous;
   c) May any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure;
   d) Reinforce or anchor offsets, bends and dead ends in pipe joined by compression couplings or bell and spigot joints to prevent failure of the pipe joint, if the offset, bend, or dead end is exposed in an excavation;
   e) Isolate the segment of pipeline in which the pressure is to be increased from any adjacent segment that will continue to be operated at a lower pressure; and
   f) If the pressure in mains or service lines, or both, is to be higher than the pressure delivered to the customer, install a service regulator on each service line and test each regulator to determine that it is functioning. Pressure may be increased as necessary to test each regulator, after a regulator has been installed on each pipeline subject to the increased pressure.
3) After complying with paragraph (2) of this section, the increase in MAOP must be made in increments that are equal to 10 psi gage or 25% of the total pressure increase, whichever produces the fewer number of increments. Whenever the requirements of paragraph (2)(f) of this section apply, there must be at least two approximately equal incremental increases.
4) If records for cast iron or ductile iron pipeline facilities are not complete enough to determine stresses produced by an internal pressure, trench loading, rolling loads, beam stresses, and other bending loads, in evaluating the level of safety of the pipeline when operating at the proposed increased pressure, the following procedures must be followed:

(continued on next page)

a) If estimating stresses, if the original laying conditions cannot be ascertained, the operator shall assume that cast iron pipe was supported on blocks with tamped backfill and that ductile pipe was laid without blocks with tamped backfill.
b) Unless the actual maximum cover depth is known, the operator shall measure the actual cover in at least three places where the cover is most likely to be greatest and shall use the greatest cover measured.
c) Unless the actual nominal wall thickness is known, the operator shall determine the wall thickness by cutting and measuring coupons from at least three separate pipe lengths. The coupons must be cut from pipe lengths in areas where the cover depth is most likely to be the greatest. The average of all measurements taken must be increased by the allowance indicated in the following table:

Pipe Size Inches (millimeters)	Allowance inches (millimeters)		
	Cast Iron Pipe		Ductile Iron Pipe
	Pit cast pipe	Centrifugally cast pipe	
3 to 8 (76 to 203)	0.075 (1.91)	0.065 (1.65)	0.065 (1.65)
10 to 12 (254 to 305)	0.08 (2.03)	0.07 (1.78)	0.07 (1.78)
14 to 24 (356 to 610)	0.08 (2.03)	0.08 (2.03)	0.075 (1.91)
30 to 42 (762 to 1067)	0.09 (2.29)	0.09 (2.29)	0.075 (1.91)
48 (1219)	0.09 (2.29)	0.09 (2.29)	0.08 (2.03)
54 to 60 (1372 to 1524)	0.09 (2.29)	-------	-------

d) For cast iron pipe, unless the pipe manufacturing process is known, the operator shall assume that the pipe is pit cast pipe with a bursting tensile strength of 11,000 psi gage and a modulus of rupture of 31,000 psi gage.

Additional Information

1) If it is determined that an uprating is necessary to fulfill capacity or pressure requirements of a distribution system, a licensed engineer or subject matter expert should be contracted to generate a written plan to ensure that all of the requirements of this Division are met.
   a) Once a written plan has been generated, it should be submitted to the Iowa Utilities Board for approval before the uprating process begins.

CITY OF BLOOMFIELD, IOWA

DIVISION THIRTEEN

Operations

49 CFR Part 192 Subpart L

Division 13.1: Scope *(Reference 192.601)*

This Division prescribes the minimum requirements for the operation of pipeline facilities.

Division 13.2: General Provisions *(Reference 192.603)*

1) No person may operate a segment of pipe unless it is operated in accordance this Division.
2) Each operator shall keep the records necessary to administer the procedures established in Division 13.3.
3) The Associate Administrator or the State Agency that has submitted a current certification under the pipeline safety laws, with respect to the pipeline facility governed by an operator's plans and procedures, may after notice and opportunity for hearing as provided in 49 CFR Part 190.206 or the relevant State procedures, require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety.

Additional Information:

1) Recordkeeping may be completed by any means that the operator chooses as long as the recordkeeping documents contain the information required to produce authentic records.
2) Recordkeeping may be completed by electronic means, or by retaining paper copies of documents.
   a) If stored electronically, consideration should be given to backing up files to a thumb drive or a remote location.
   b) If paper documents are completed and retained, consideration should be given to storing files in a location that provides additional protection from water damage or fire hazards.
3) All records produced and retained by the operator must be available upon request by the Federal or State agency for the specified retention period of that record.

Division 13.3: Procedure Manual for Operations, Maintenance, and Emergencies *(Reference 192.605)*

1) *General* – Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be prepared before operations of a pipeline system commence and appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.
   a) **This Plan must be reviewed and updated (if necessary), by the operator at least once each calendar year, but not to exceed 15 months.**
2) *Maintenance and Normal Operations* – The manual required by paragraph (1) of this Division must include procedures for the following, if applicable, to provide safety during maintenance and operations.
   a) Operating, maintaining, and repairing the pipeline in accordance with each section of the requirements of Division 13 and 14 of this Plan.
   b) Controlling corrosion in accordance with the operations and maintenance requirements of Division 10 of this Plan.
   c) Making construction records, maps, and operating history available to appropriate operating personnel.
   d) Gathering of data needed for reporting incidents according to Division 1 in a timely and effective manner.
   e) Starting up and shutting down any part of the pipeline in a manner designed to assure operation within the MAOP limits, plus the build-up allowed for operation of pressure-limiting and control devices.
   f) Periodically reviewing the work done by operator personnel to determine the effectiveness, and adequacy of the procedures used in normal operation and maintenance and modifying the procedures when deficiencies are found.
      i) **Review of procedure effectiveness may be completed annually or as often as necessary if at any time, procedures are found to be inadequate. This review may be conducted during the completion of operations and maintenance activities throughout the year or during simulations.**
   g) Taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas, and making available when needed at the excavation, emergency rescue equipment, including breathing apparatus and, a rescue harness and line.
   h) Systematic routine testing and inspection of pipe-type or bottle-type holders including:
      i) Provision for detecting external corrosion before the container has been impaired.
      ii) Periodic sampling and testing of stored gas to determine dew point of vapors contained.

(continued on next page)

iii) Periodic inspection and testing of pressure limiting equipment to determine that it is in safe operating condition and has adequate capacity.

i) Responding promptly to a report of a gas odor inside or near a building, unless these procedures are included in the operator's emergency procedures.

i) **Procedures for responding promptly to reports of gas leaks or odors is provided in the O&M Emergency Plan and Procedures.**

3) *Abnormal Operation* – The requirements of abnormal operation DO NOT apply to operators that are operating transmission pipeline in connection with their distribution systems, with one exception.

a) The exception is that if MAOP plus allowable build-up is exceeded on transmission pipelines, it must be reported to PHMSA and the State Agency according to Part 2.5 - Transmission MAOP Exceedance of the O&M Emergency Plan and Procedures.

4) *Safety-Related Condition Reports* – The manual must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of Division 1.9 of this Plan.

5) *Continuing Surveillance, Emergency Response, and Accident Investigation* – The procedures required by Division 13.7(192.613(a)), Division 13.9(192.615), and Division 13.11(192.617) must be included in this manual.

Additional Information:

1) Operations and Maintenance Plans may be altered or adjusted to specifically apply to the facilities contained within the operator's gas system.

a) Only procedures that apply specifically to the operator's pipelines, need to be included in the manual.

2) Supplemental materials, not required by 49 CFR Part 192, may be added to this manual at any time. However, any additions made to this Plan may be subject to Federal or State inspections upon request.

Division 13.4: Verification of Pipeline Material Properties and Attributes: Onshore Steel Transmission Pipelines *(Reference 192.607)*

NOTE: This Division ONLY applies to steel transmission pipelines.

1) Transmission pipeline operators must document and verify material properties and attributes in accordance with this Division.
2) ***Documentation of Material Properties and Attributes*** - Records documenting physical pipeline characteristics and attributes must include the following and be maintained for life of the pipeline and be traceable, verifiable, and complete.
   i) Diameter
   ii) Wall Thickness
   iii) Seam Type
   iv) Grade of pipe (yield strength, ultimate tensile strength, or pressure rating for valves, fittings, flanges, etc.)
   v) Charpy v-notch toughness values that meet the requirements of ECA method found in §192.624(c)(3) or the fracture mechanic requirements found in §192.712.
3) ***Verification of Material Properties and Attributes*** – If an operator DOES NOT have traceable, verifiable, and complete records required by paragraph (2) of this Division, the operator must develop and implement procedures for conducting nondestructive or destructive tests, examinations, and assessments in order to verify material properties of both aboveground and buried line pipe and components when excavations occur at the following opportunities:
   i) Anomaly direct examinations
   ii) Repairs
   iii) Remediations
   iv) Maintenance
   v) Excavations that are associated with replacements or relocations
   vi) Excavations that are NOT directly related to pipeline maintenance or repairs, but may provide an opportunity to easily access the pipeline. This may also be considered "in situ" evaluations.

   a) The procedures must also provide for the following requirements:
      i) For nondestructive tests, at each test location, material properties for minimum yield strength and ultimate tensile strength must be determined at a minimum of 5 places in at least 2 circumferential quadrants of the pipe for a minimum of 10 test reading at each pipe cylinder location.
      ii) For destructive tests, at each test location, a set of material properties tests for minimum yield strength and ultimate tensile strength must be conducted on each test pipe cylinder removed from each location, in accordance with API Specification 5L.
      iii) Tests, examinations, and assessments must be appropriate for verifying the necessary material properties and attributes.
      iv) If toughness properties are not documented, the procedures must include accepted industry methods for verifying pipe material toughness.

(continued on next page)

v) Verification of material properties and attributes for non-line pipe components must comply with paragraph (6) of this Division.

4) ***Special Requirements for Nondestructive Methods*** – Procedures developed in accordance with paragraph (3) of this Division for verification of material properties and attributes using nondestructive testing methods must:
   a) Use methods, tools, procedures, and techniques that have been validated by a subject matter expert based on comparison with destructive test results on material of comparable grade and vintage;
   b) Conservatively account for measurement inaccuracy and uncertainty using reliable engineering tests and analyses; and
   c) Use test equipment that has been properly calibrated for comparable test materials prior to usage.

5) ***Sampling Multiple Segments of Pipe*** – To verify material properties and attributes for a population of multiple, comparable segments of pipe without traceable, verifiable, and complete records, an operator may use a sampling program in accordance with the following requirements:
   a) The operator must define separate populations of similar segments of pipe for each combination of the following material properties and attributes: Nominal wall thicknesses, grade, manufacturing process, pipe manufacturing dates, and construction dates. If the dates between the manufacture or construction of the pipeline segments exceeds 2 years, those segments cannot be considered as the same vintage for the purpose of defining a population under this section. The total population mileage is the cumulative mileage of pipeline segments in the population. The pipeline segments need not be continuous.
   b) For each population defined according to paragraph (5)(a) listed above, the operator must determine material properties at all excavations that expose the pipe associated with anomaly direct examinations, *in situ* evaluations, repairs, remediations, or maintenance, except for pipeline segments exposed during excavation activities pursuant to §192.614, until completion of one excavation per mile rounded up to the nearest whole number
   c) If the test results identify line pipe with properties that are not consistent with available information or existing expectations or assumed properties used for operations and maintenance in the past, the operator must establish an expanded sampling program. The expanded sampling program must use valid statistical bases designed to achieve at least a 95% confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. Operators must notify PHMSA in advance of using an expanded sampling approach in accordance with §192.18.

(continued on next page)

d) An operator may use an alternative statistical sampling approach that differs from the requirements specified in paragraph (5)(b) of this section. The alternative sampling program must use valid statistical bases designed to achieve at least a 95% confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. Operators must notify PHMSA in advance of using an alternative sampling approach in accordance with §192.18.

6) ***Components*** - For mainline pipeline components other than line pipe, an operator must develop and implement procedures in accordance with paragraph (3) of this section for establishing and documenting the ANSI rating or pressure rating in accordance with ASME/ANSI B16.5.
   a) Operators are not required to test for the chemical and mechanical properties of components in compressor stations, meter stations, regulator stations, separators, river crossing headers, mainline valve assemblies, valve operator piping, or cross-connections with isolation valves from the mainline pipeline.
   b) Verification of material properties is required for non-line pipe components, including valves, flanges, fittings, fabricated assemblies, and other pressure retaining components and appurtenances that are:
      i) Larger than 2 inches in nominal outside diameter
      ii) Material grades of 42,000 psi (Grade X42) or greater, or
      iii) Appurtenances of any size that are directly installed on the pipeline and cannot be isolated from mainline pipeline pressures.
   c) Procedures for establishing material properties of non-line pipe components must be based on the documented manufacturing specification for the components. If specifications are not known, usage of manufacturer's stamped, marked, or tagged material pressure ratings and material type may be used to establish pressure rating. Operators must document the method used to determine the pressure rating and the findings of that determination.

7) ***Uprating*** – The material properties determined from the destructive or nondestructive tests required by this section cannot be used to raise the grade or specification of the material, unless the original grade or specification is unknown and MAOP is based on an assumed yield strength of 24,000 psi in accordance with §192.107(b)(2).

Division 13.5: Change in Class Location – Required Study *(Reference 192.609)*

NOTE: This Division only applies to existing steel pipelines (distribution and/or transmission) that operate at a hoop stress of more than 40% SMYS.

1) Whenever an increase in population density indicates a change in class location for an existing steel pipeline operating at a hoop stress that is more than 40% SMYS, or indicates that the hoop stress corresponding to the established MAOP for a segment of existing pipeline is not commensurate with the present class location, the operator shall immediately make a study to determine the following:
   a) The present class location for the existing segment involved.
   b) The design, construction, and testing procedures followed in the original construction, and a comparison of these procedures with those required for the present class location by the applicable provisions of this Division.
   c) The physical condition of the segment to the extent it can be ascertained from available records;
   d) The operating and maintenance history of the segment;
   e) The MAOP and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved; and
   f) The actual area affected by the population density increase, and physical barriers or other factors which may limit further expansion of the more densely populated area.

Division 13.6: Change in Class Location – Confirmation or Revision of MAOP

(Reference 192.611)

1) If the hoop stress corresponding to the established MAOP of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the MAOP of that segment must be confirmed or revised according to one of the following requirements:
   a) If the segment involved has been previously tested in place for a period not less than 8 hours:
      i) The MAOP is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72% of the SMYS of the pipe in Class 2 locations, 60% of SMYS in Class 3 locations, or 50% of SMYS in Class 4 locations.
      ii) The alternative MAOP is 0.8 times the test pressure in Class 2 locations and 0.667 times the test pressure in Class 3 locations. For pipelines operating at alternative MAOP (according to §192.620), the corresponding hoop stress may not exceed 80% of SMYS of the pipe in Class 2 locations and 67% of SMYS in Class 3 locations.
   b) The MAOP of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by this Plan for new segments of pipelines in the existing class location.
   c) The segment involved must be tested in accordance with the applicable requirements of Division 11 of this Plan, and its MAOP must then be established according to the following criteria:
      i) The MAOP after the requalification test is 0.8 times the test pressure for Class 2 locations, 0.667 times the test pressure in Class 3 locations, and 0.555 times the test pressure for Class 4 locations.
      ii) The corresponding hoop stress may not exceed 72% of SMYS of the pipe in Class 2 locations, 60% SMYS in Class 3 locations, or 50% SMYS in Class 4 locations.
      iii) For pipeline operating at an alternative MAOP (according to §192.620), the alternative MAOP after the requalification test is 0.8 times the test pressure for Class 2 locations and 0.667 times the test pressure for Class 3 locations. The corresponding hoop stress may not exceed 80% of SMYS of the pipe in Class 2 locations and 67% of SMYS in Class 3 locations.
2) The MAOP confirmed or revised in accordance with this Division, may not exceed the MAOP established before the confirmation or revision.
3) Confirmation or revision of the MAOP of a segment of pipeline in accordance with this Division does not preclude the application of §192.553 and §192.555.
4) Confirmation or revision of the MAOP that is required as a result of a study required by Division 13.5 of this Plan must be completed within 24 months of the change in class location. Pressure reduction according to paragraphs (1)(a) or (1)(b) of this Division within the 24-month period does not preclude establishing a MAOP under paragraph (1)(c) of this Division at a later date.

Division 13.7: Continuing Surveillance *(Reference 192.613)*

1) Each operator shall have procedures for continuing surveillance of its pipeline facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.
2) If a pipeline segment is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved, or if the segment cannot be reconditioned or phased out, the MAOP of the pipeline must be reduced according to §192.619(a) and (b).

Additional Information:

1) Continuing surveillance on pipeline facilities may be conducted during the completion of routine operations and maintenance activities described in this Plan.
   a) Continuing surveillance may also be conducted anytime an operator has visual access to the pipeline route or facilities that allows the operator to visually identify the following items:
      i) Excavation activities
      ii) Encroachments
      iii) Pipeline exposures
      iv) Changes in population densities
      v) Flooding
      vi) Erosion
      vii) Excessive snow or ice build-up
2) If at any time, abnormal or unusual conditions are found, the conditions should be evaluated for potential safety concerns and remedial action should be scheduled and taken as described in this Plan for the specific condition that has been identified.
3) Periodic review of operations and maintenance records may be conducted in an attempt to identify safety concerns or conditions that may affect the safe operation of the pipeline.
   a) A review of the systems Distribution Integrity Management Plan may be used as an additional resource to attempt to identify pipeline threats and trends in pipeline leaks and/or failures.

Division 13.8: Damage Prevention Plan *(Reference 192.614 & Iowa Code 480)*

NOTE: All operators must participate and be a member with the Iowa One-Call system to fulfill the requirements of this Damage Prevention Plan. This Damage Prevention Plan is intended to protect lives and property by reducing the chance of damage to pipelines during excavation activities.

Definitions:

1) *Damage* – Any impact with, destruction, impairment, or penetration of, or removal of support from an underground facility, including damage to its protective coating, housing, or device.
2) *Emergency* – A conditions where there is clear and immediate danger to life, health, essential services, or a potentially significant loss of property.
3) *Excavation* – An operation in which a structure or earth, rock, or other material in or on the ground is moved, removed, or compressed, or otherwise displaced by means of any tools, equipment, or explosives and includes but is not limited to grading, trenching, tiling, digging, ditching, drilling, auguring, tunneling, scraping, cable or pipe plowing, driving, and demolition of structures.
   a) *Excavation Does Not Include the Following* – Farming operations, residential or commercial gardening, the opening of a grave site in a cemetery, normal activities involved in land surveying pursuant to Iowa Code Chapter 542B, operations in a solid waste disposal site which has planned for underground facilities, the replacement of an existing traffic sign at its current location and no more than its current depth, and normal road or highway maintenance which does not change the original grade of the roadway or the ditch.
4) *Normal Farming Operations* – Plowing, cultivation, planting, harvesting, and similar operations routine to most farms, but excludes chisel plowing, sub-soiling, or ripping more than 15 inches in depth, drain tile excavating, terracing, digging or driving a post in a new location.
5) *Operator* – A person owning or operating an underground facility including but not limited to public, private, and municipal utilities. An operator does NOT include a person who owns or otherwise lawfully occupies real property where an underground facility is located only for the use and benefit of the owner or occupant on the property.

Required Notice – Location and Marking of Underground Facilities:

1) At least 48 hours prior to any excavation, an excavator shall contact Iowa One-Call and provide notice of the planned excavation.
   a) The required 48-hour notice excludes Saturdays, Sundays, and legal holidays.
   b) Notices received by Iowa One-Call after 5:00 pm shall be processed as if received at 8:00 am the next business day.
   c) The notice will be valid for 20 calendar days from the date the notification was provided to Iowa One-Call.
   d) If all locating and marking of underground facilities is completed prior to the expiration of the 48-hour period, the excavator may proceed with the excavation as long as they have been notified by Iowa One-Call that the locating and marking is complete.

(continued on next page)

Required Notice – Required Information within City Limits:

1) Any notice provided to Iowa One-Call for excavations within city limits must include the following information:
   a) Street address or block and lot numbers
   b) Name and address of excavator
   c) Excavator's telephone number
   d) The type and extent of the proposed excavation
   e) Whether or not explosives are going to be used
   f) Approximate location of the excavation on the property
   g) If known, the name of the housing development and property owner

Required Notice – Required Information outside City Limits:

1) Any notice provided to Iowa One-Call for excavations outside of city limits must include the following information:
   a) Name of the county, township, range, and section
   b) Name and address of excavator
   c) Excavator's telephone number
   d) The type and extent of the proposed excavation
   e) Whether or not explosives are going to be used
   f) Approximate location of the excavation on the property
   g) If known, the quarter section, 911 address and global positioning system coordinate, name of property owner, name of housing development with street address or block and lot numbers, or both.

White Lining of Proposed Excavation:

1) The area of the proposed excavation must be clearly identified by one of the following methods:
   a) Physical pre-marking with white flags or paint.
   b) Electronic means of white-lining utilizing the electronic notification process.
   c) On-site preconstruction meetings.

Once a Notice is Received:

1) The operator shall, at no cost, locate and mark the horizontal location of the underground facilities within 48 hours of the notice being received from Iowa One-Call unless otherwise agreed upon by the operator and excavator. The 48 hours excludes Saturdays, Sunday, and legal holidays.
   a) The horizontal location of any underground utility is defined as including an area eighteen inches on either side of the underground utility. Also known as the tolerance zone.
   b) Marking must conform with the uniform color code established by the American Public Works Associations Utility Location and Coordination Council. Yellow paint and/or flags must be used.
2) Once the locating and marking has been completed, within the 48-hour time frame, the operator must notify (also called positive response) Iowa One-Call that the marking is complete.

(continued on next page)

3) If, in the opinion of the operator, the excavation requires precise location of the underground utilities, the excavator, unless otherwise agreed upon between the excavator and the operator, shall hand dig test holes to determine the exact location of the facilities, unless the operator specifies an alternate method (potholing/vacuum excavation).
4) The marking must be done in a manner (paint and/or flags) that will last for a minimum of five working days on any nonpermanent surface, or a minimum of ten working days on any permanent surface. If the excavation will continue for a longer period of time, the operator shall remark the location of the underground facility upon request of the excavator. Iowa One-Call must be notified for remark requests.
5) It is the responsibility of the excavator to ensure markings are not removed or destroyed.
6) The only exception to the 48-hour pre-excavation notification shall be when an emergency exists. During an emergency, excavation operations may begin immediately, provided reasonable precautions are taken to protect the underground facilities. Even during an emergency, the excavator shall notify Iowa One-Call of the excavation as soon as practical.

No Underground Utilities in Proposed Excavation Area:

1) If, during the locating and marking process, the operator determines that they do not have any underground utilities in the proposed excavation area, the operator must, within the 48-hour timeframe, notify Iowa One-Call that the area is clear. The 48-hours excluded Saturdays, Sundays, and legal holidays.

Natural Gas Transmission Line "Stand-by" Requirements:

1) No excavation shall take place within 25 feet of an underground natural gas transmission pipeline without a representative of the operator present (on-site) during the excavation, unless otherwise agreed by the operator and the excavator in writing.
2) This requirement does not apply when a representative of the operator fails to be present at the proposed excavation area at the time the work is scheduled to commence or as otherwise agreed by the operator and excavator in writing.
3) It is recommended that the Excavation "Stand-by" Report is completed any time that an excavator is planning on digging within 25 feet of a natural gas transmission pipeline so that proper documentation may be generated, obtained and recorded.

Damage Caused to Underground Facilities:

1) An excavator must as soon as practical notify the operator when any damage occurs to an underground facility as a result of the excavation. The notice shall include the type of facility damaged, and the extent of the damage. If damage occurs, and excavator must not backfill the area until the damage has been investigated by the operator, or the operator authorizes backfilling.
2) If the damage results in an emergency, the excavator shall take all reasonable actions to alleviate the emergency including but not limited to the evacuation of the affected area. The excavator shall leave all equipment situated where the equipment was at the time the emergency was created and immediately contact the operator and appropriate authorities and necessary emergency response agencies.

(continued on next page)

3) It is recommended that a list be generated and maintained for all excavators who damage utilities. This would allow an operator to track or define who is damaging utilities or who is not following Iowa One-Call laws.
    a) This information may be added to an operators Distribution Integrity Management Plan to provide additional means of trending and tracking.

Receiving and Recording Locate Requests:

1) The operator shall have a procedure in place for receiving notification of proposed excavations from Iowa One-Call.
    a) See Notification of Locate Requests of the O&M Emergency Plan and Procedures for specific details.
2) The operator shall maintain a record (either electronically or by paper) for pipeline location requests received, which will be maintained for a minimum of five years following the date of the request.
3) Additional information that may be necessary to demonstrate compliance with Iowa One-Call laws and for Operator Qualification verification is the name of the person who performed the locating and marking, and the date and time the request was completed.

Inspection of Excavation Activities:

1) The operator shall make on-site inspections whenever there is reason to believe the activities taking place could potentially damage pipeline facilities. Consideration should be given to the following to determine the frequency and extent of inspections:
    a) Type and duration of excavation activities.
    b) Proximity of pipelines to excavation.
    c) Type of excavation equipment being used.
    d) Potential consequences of a pipeline being hit.
    e) Previous experience with excavator not following safe digging practices or Iowa Once-Call laws.
    f) Pipeline materials and/or operating pressure.
2) If at any time, the excavation has included blasting, a subsequent leak survey must be conducted using gas detection equipment.

Division 13.8.1: Damage Prevention – Guidelines for Directional Drilling and Other Trenchless Technologies

NOTE: The following guidelines are recommended anytime directional drilling or trenchless technologies are being used. For specific pipeline procedures, see IAMU Procedure #2.6 – Installation of Pipelines by Trenchless Technologies.

1) White line proposed directional drilling path including entrance and exit pit locations.
2) Notify Iowa-One Call of proposed excavation (directional drilling) to have all underground facilities located and marked.
   a) If directional drilling will be conducted on private property, an attempt should be made to contact the property owner and have the private utilities marked and located as Iowa One-Call DOES NOT require facility owner/operators to locate and mark private utilities.
3) After the required 48-hours has elapsed (unless notified by Iowa One-Call), verify that all facilities in the area have been located and marked.
4) Facilities that are in the immediate work area should be exposed by hand digging or by vacuum excavation prior to commencing directional drilling to verify exact location and depth.
5) Facilities that cross the proposed path of directional drilling should be exposed by hand digging or by vacuum excavation prior to commencing directional drilling to verify exact location and depth.
6) Careful consideration should be given to sewer systems within the area. Sewer system are especially vulnerable to damage from directional drilling for the following reasons:
   a) Lines are often non-metallic, making them difficult to locate.
   b) Clean-outs or other indications of laterals may be hidden or non-existent.
   c) Damage may not be readily apparent when a sewer line is pierced by a directional drilling machine (especially gravity flow systems).
7) It may be necessary to utilize specialized cameras inserted into the sewer line to verify that directional boring has not caused damage or pierced the line.

Division 13.8.2: Damage Prevention – Protecting Existing Gas Pipelines During Directional Drilling

NOTE: The following guidelines are recommended anytime directional drilling or trenchless technologies are being used near existing gas pipeline facilities. For specific pipeline installation procedures, see IAMU Procedure #2.6 – Installation of Pipelines by Trenchless Technologies.

1) When excavations near gas facilities will be conducted by directional drilling or other trenchless technologies, the operator should consider the following:
    a) When it is anticipated that the bore will cross over/under or come within the 18” tolerance zone established by Iowa One-Call for an existing gas facility, the facility should be exposed by hand digging or vacuum excavation, to determine the exact location, depth, and to ensure adequate separation.
    b) When the bore will run parallel to an existing gas pipeline, the pipeline should be exposed by hand digging or vacuum excavation at designated intervals or by using locating technology to verify that adequate clearance is maintained between the bore and the existing pipeline during the drilling of the pilot hole and during the back reaming process.
        i) The calculated separation distance should account for the largest diameter back reamer that will be used during the boring process.
    c) Where potholes (vacuum excavations) are used for visual verification, they should be placed at intervals that will ensure that clearance is maintained during boring operations. Factors to consider for required intervals include the following:
        i) Proximity of proposed bore path to the gas pipeline.
        ii) Type of facility (existing and proposed).
        iii) Type of soil.
        iv) Size and controllability of the bore head.
2) If at any time there is reason to believe that damage has been sustained by the existing gas pipeline, it is recommended that a leak survey be conducted using gas detection equipment in the area affected by the directional drilling.

Division 13.9: Emergency Plans *(Reference 192.615)*

NOTE: See the O&M Emergency Plan and Procedures for specific procedures to minimize the hazards resulting from a gas pipeline emergency.

1) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:
    a) Receiving, identifying, and classifying notices of events that require immediate response by the operator.
    b) Establishing and maintaining adequate means of communication with appropriate fire, police and other public officials.
    c) Prompt and effective response to a notice of each type of emergency, including the following:
        i) Gas detected inside or near a building.
        ii) Fire located near or directly involving a pipeline facility.
        iii) Explosion occurring near or directly involving a pipeline facility.
        iv) Natural disaster.
    d) The availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency.
    e) Actions directed toward protecting people first and then property.
    f) Emergency shutdown and pressure reduction in any section of the operator's pipeline system necessary to minimize hazards to life or property.
    g) Making safe any actual or potential hazard to life or property.
    h) Notifying appropriate fire, police, and other public officials of gas pipeline emergencies and coordinating with them both planned responses and actual responses during an emergency.
    i) Safely restoring any service outage.
    j) Beginning action under Division 13.11 of this Plan, if applicable, as soon after the end of the emergency as possible.
2) Each operator shall:
    a) Furnish its supervisors who are responsible for emergency action a copy of that portion of the latest edition of the emergency procedures established by this Division as necessary for compliance with those procedures.
    b) Train the appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and verify that the training is effective.
    c) Review employee activities to determine whether the procedures were effectively followed in each emergency.
3) Each operator shall establish and maintain liaison with appropriate fire, police, and other public officials to:
    a) Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency;
    b) Acquaint the officials with the operator's ability in responding to gas pipeline emergency;
    c) Identify the types of gas pipeline emergencies of which the operator notifies the officials; and
    d) Plan how the operator and officials can engage in mutual assistance to minimize the hazards to life or property.

Division 13.10: Public Awareness *(Reference 192.616)*

NOTE: See the IAMU Model Distribution Public Awareness Plan for the specific procedures that meet the requirements of API RP 1162. If the operator has selected a different public awareness plan than the one provided by IAMU, a Plan must be developed, implemented and be available for inspection by Federal or State authorities.

1) Except for an operator of a master meter or petroleum gas system covered under paragraph 2 of this Division, each pipeline operator must develop and implement a written continuing public education program that follows the guidance provided in the American Petroleum Institute's Recommended Practice 1162 (API RP 1162) which has been incorporated by reference into 49 CFR Part 192.
2) Unless the operator transports gas as a primary activity, the operator of a master meter or petroleum gas system is not required to develop a public awareness program. Instead, the operator must develop and implement a written procedure to provide its customers public awareness messages twice annually. If the master meter or petroleum gas system is located on property the operator does not control, the operator must provide similar messages twice annually to persons controlling the property. The public awareness message must include the following:
    a) A description of the purpose and reliability of the pipeline;
    b) An overview of the hazards of the pipeline and prevention measures used;
    c) Information about damage prevention;
    d) How to recognize and respond to a leak; and
    e) How to get additional information.

Division 13.11: Investigation of Failures *(Reference 192.617)*

Each operator shall establish procedures for analyzing accidents and failures, including the selection of samples of the failed facility or equipment for laboratory examination, where appropriate, for the purpose of determining the causes of the failure and minimizing the possibility of recurrence.

Investigation Process:

1) Investigations must be conducted on all Federally reportable incidents as defined in Division 1.2 of this Plan.
    a) The investigation should be completed in a manner that aids in determining the root cause of the incident or failure and minimizes the possibility of recurrence.
    b) Although, not required, consideration should be given to performing investigations on Grade 1 leaks that did not result in a Federally reportable incident so that leak data may be gathered and potential failure patterns established.
2) Failure investigations may be completed "in-house" or by contracting a subject matter expert (SME) or an outside source with experience in incident or failure investigations.
    a) If an "in-house" investigation is conducted, the information contained in the 30-day written incident report filed with PHMSA may provide an adequate investigation of the incident or failure.
3) If the incident was a result of a failure of pipe or pipeline components and a detailed analysis of the pipe or pipeline component is necessary to determine the root cause of the incident, the pipe or pipeline component must be sent to a laboratory for testing.
    a) When gathering failed pipe or pipeline components for testing, care must be taken so that additional damage or contamination is not sustained by the failed pipe or component.
    b) If possible, deliver/send the failed pipe or component to the laboratory "as is" without cleaning or tampering in any way.
4) Testing and analysis completed by the laboratory on the failed pipe or component must be retained and reviewed by the operator.
    a) After review, the operator must determine if additional actions or preventative measures are necessary in other areas of the pipeline that contain the same type of failed pipe or component that were involved in the incident.

Division 13.12: Maximum Allowable Operating Pressure – Steel or Plastic Pipelines *(Reference 192.619)*

1) No person may operate a segment of steel or plastic pipeline at a pressure higher than the maximum allowable operating pressure (MAOP) determined according to paragraph 3), 4), or 5) of this Division, or the lowest of the following:
   a) The design pressure of the weakest element in the pipeline segment that was determined according to requirements in Division 4 and Division 5 of this Plan. However, for steel pipelines converted under §192.14 or uprated according to Division 12 of this Plan, if any variable necessary to determine the design pressure is unknown, one of the following pressures is to be used as the design pressure.
      i) 80% of the first test pressure that produces yield under section N% of Appendix N of ASME B31.8, reduced by the appropriate factor in paragraph 1)(b)(ii) of this Division; or
      ii) If the pipe is 12 ¾ inches or less in outside diameter and is not tested to yield under this paragraph, 200 psi.
   b) The pressure obtained by dividing the pressure to which the pipeline 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.
      ii) For steel pipe operated at 100 psi or more, the test pressure is divided by a factor determined in accordance with the following Table:

Class Location	Installed before Nov. 12, 1970	Factors		
		Installed after Nov. 11, 1970 and before July 1, 2020	Installed on or after July 1, 2020	Converted under §192.14
1	1.1	1.1	1.25	1.25
2	1.25	1.25	1.25	1.25
3	1.4	1.5	1.5	1.5
4	1.4	1.5	1.5	1.5

   c) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements of 1)(b) of this Division after the applicable date in the third column or the segment was uprated according to the requirements in Division 12 or this Plan.

Pipeline Segment	Pressure Date	Test Date
All pipelines	July 1, 1970	July 1, 1965

(continued on next page)

   d) The pressure determined by the operator to be the maximum safe pressure after considering and accounting for records of material properties, including material properties verified in accordance with Division 13.4 of this Plan, if applicable, and the history of the pipeline segment, including known corrosion and actual operating pressure.
2) No person may operate a segment to which paragraph 1)(d) of this Division is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the MAOP from being exceeded as described in Division 5.18 of this Plan.
3) The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding July 1, 1970. The operator must still comply with Division 13.6 of this Plan.
4) The operator of a pipeline segment of steel pipeline meeting the conditions prescribed in §192.620(b) may elect to operate the segment at a MAOP determined under §192.620.
   NOTE: This Plan does not provide procedures or requirements for Alternative MAOP for Certain Steel Pipelines (§192.620). If an operator must determine an MAOP according to §192.620, specific requirements and procedures must be inserted into this Plan.
5) Notwithstanding the requirements in paragraphs 1) through 4) of this Division, operators of onshore steel transmission pipelines that meet the criteria specified in Division 13.15 must establish and document MAOP in accordance with §192.624.
6) Operators of onshore steel transmission pipelines must make and retain records necessary to establish and document MAOP of each pipeline segment in accordance with paragraphs 1) through 5) of this Division as follows:
   a) Operators of pipelines in operation as of July 1, 2020 must retain any existing records establishing MAOP for the life of the pipeline;
   b) Operators of pipelines in operation as of July 1, 2020 that do not have records establishing MAOP and are required to reconfirm MAOP in accordance with Division 13.15 of this Plan, must retain the records reconfirming MAOP for the life of the pipeline; and
   c) Operators of pipelines placed in operation after July 1, 2020 must make and retain records establishing MAOP for the life of the pipeline.

Additional Information:
1) It is recommended that the Determination of MAOP in Natural Gas Pipelines document is completed any time service lines, mains, or transmission lines are installed.
2) The Determination of MAOP in Natural Gas Pipelines document may be found on the next three pages of this Plan.
3) For additional procedures on how to operate a gas system within an established MAOP, see IAMU Procedure #8.17 - Operate Within an Established MAOP.

DETERMINATION OF MAOP IN NATURAL GAS PIPELINES

Identity of Pipeline/Distribution Area ____

A. Maximum Allowable Operating Pressure: Steel or Plastic Pipelines (Part 192.619): and High-Pressure Distribution Systems (Part 192.621).

Part 192.619(a)(1) Design Pressure: Lowest design pressure

Part 192.621(a)(1) for any of the following system elements

Pipe (including service lines)	______________________
Valves	______________________
Flanges	______________________
Fittings	______________________
Mechanical Couplings	______________________
Leak Clamps	______________________
Instruments (odorizers, heaters, etc.)	______________________
Overpressure Protection Devices	______________________
Upstream Regulator(s)-Outlet Pressure Rating	______________________
Downstream Regulators-Inlet Pressure Rating	______________________
Other (list)	______________________

Part 192.619(a)(2) Pressure Test

Plastic Pipe: Test Pressure divided by 1.5 ______________________

Steel Pipe operated at or over 100 psi,

Test Pressure divided by Class Location Factor ________________________

Part 192.619(a)(3) Historic Operations

Highest operating pressure between 7/l/65 and 7/l/70 unless the pressure test in (a)(2) was after 7/l/65 or an uprating in accordance with Subpart K has been conducted. ________________________

Part 192.619(a)(4) Furnace butt welded steel pipe:

60% of mill test pressure ________________________

Part 192.619(a)(5) All other steel pipe:

85% of mill or post installation pressure test, whichever is higher ________________

B. Part 192.621: High Pressure Distribution Systems Only.

Part 192.621(a)(2) 60 psig unless all services have overpressure protection ________________________

Part 192.621(a)(3) 25 psig for any cast iron pipe with unreinforced joints ________________________

Part 192.621(a)(4) Pressure limit on joints. ________________________

C. Part 192.619(a)(6) and Part 192.621(a)(5):

Additional Consideration for Transmission or High-Pressure Distribution Lines.

Highest operating pressure considered safe based on operating history ________________________

D. Part 192.623: Low Pressure Distribution Systems.

Highest delivery pressure which can be safely applied to customer piping and properly adjusted gas appliances. ____________________

E. Part 192.619(c): Alternate consideration for transmission lines.
Highest operating pressure between 7/1/65 and 7/1/70 (7/1/71 and 7/1/76 for offshore gathering lines.)

F. Determination of MAOP.

Either item E., where applicable, or the lowest pressure on any of the above lines is the MAOP.

MAOP:____

Date(s) of Uprating (if applicable)____________________

Describe the uprating process: ____

____

____

____

____

____

____

____

Continue on back if needed.

By:____

Date:____

NOTE: This form may be used to establish maximum allowable operating pressure (MAOP) for steel or plastic pipelines. MAOP documents must be retained for the life of the system.

Division 13.13: Maximum Allowable Operating Pressure – High Pressure Distribution Systems *(Reference 192.621)*

1) No person may operate a segment of a high-pressure distribution system (pressures above 1 psi) at a pressure that exceeds the lowest of the following pressures, as applicable:
   a) The design pressure of the weakest element in the segment, determined in accordance with Division 4 and Division 5 of this Plan.
   b) 60 psi, for a segment of distribution system otherwise designed to operate at above 60 psi, unless the service lines in the segment are equipped with service regulators or other pressure limiting devices in a series that meet the requirements of Division 5.19 of this Plan.
   c) 25 psi in segments of cast iron pipe in which there are unreinforced bell and spigot joints.
   d) The pressure limits to which a joint could be subjected without the possibility of its parting.
   e) 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.
2) No person may operate a segment of pipeline to which paragraph 1) e) of this Division applies, unless overpressure protective devices are installed on the segment in a manner that will prevent the MAOP from being exceeded according to Division 5.18 of this Plan.

Division 13.14: Maximum Allowable Operating Pressure – Low Pressure Distribution Systems *(Reference 192.623)*

Requirements and procedures for MAOP in low pressure systems (less than 1 psi) are not included in this Plan. If an operator must operate low pressure segments of pipeline, requirements and procedures must be developed and incorporated into this Plan.

Division 13.15: Maximum Allowable Operating Pressure Reconfirmation– Onshore Steel Transmission Pipelines *(Reference 192.624)*

Applicability:

1) Operators of onshore steel transmission pipeline segments must reconfirm the MAOP of all pipeline segments in accordance with this Division if either of the following requirements are met:
   a) Records necessary to establish MAOP in accordance with §192.619(a)(2), including records required by Division 11.10, are not traceable, verifiable, and complete and the pipeline is located in one of the following locations:
      i) A high consequence area (HCA); or
      ii) A Class 3 or 4 location.
   b) The pipeline segment's MAOP was established in accordance with §192.619(c), the pipeline segment's MAOP is greater than or equal to 30% of SMYS, and the pipeline segment is located in one of the following areas:
      i) A high consequence area (HCA);
      ii) A Class 3 or 4 location; or
      iii) A moderate consequence area as defined in Division 2.1 of this Plan, if the pipeline segment can accommodate inspection by means of instrumented inline inspection tools.

Procedures and Completion Dates:

1) Operators of a pipeline subject to this Division must develop and document procedures for completing all actions required by this Division by July 1, 2021. These procedures must include a process for reconfirming MAOP for any pipelines that meet a condition described in the Applicability section of this Division, and for performing a spike test or material verification in accordance with Division 11.4 and Division 13.4 of this Plan, if applicable. All actions required by this section must be completed according to the following schedule:
   a) Operators must complete all actions required by this Division on at least 50% of the pipeline mileage by July 3, 2028.
   b) Operators must complete all actions required by this Division on 100% of the pipeline mileage by July 2, 2035 or as soon as practicable, but not to exceed 4 years after the pipeline segment first meets a condition of the Applicability section of this Division, whichever is later.
   c) If operational and environmental constraints limit an operator from meeting the deadlines in this Division, the operator may petition for an extension of the completion deadlines by up to 1 year, upon submittal of a notification in accordance with Division 2.8 of this Plan. The notification must include an up-to-date plan for completing all actions in accordance with this Division, the reason for the requested extension, current status, proposed completion date, outstanding remediation activities, and any needed temporary measures needed to mitigate the impact on safety.

(continued on next page)

MAOP Determination:
Operators of a pipeline segment meeting a condition listed in the Applicability section of this Division must reconfirm its MAOP using one of the following methods:

Method 1: Pressure Test – Perform a pressure test and verify material properties records in accordance with Division 13.4 of this Plan and the following requirements:
1) *Pressure Test* – Perform a pressure test in accordance with Division 11 of this Plan. The MAOP must be equal to the test pressure divided by the greater of either 1.25 or the applicable class location factor in §192.619(a)(2)(ii).
2) *Material Properties Records* – Determine if the following material properties records are documented in traceable, verifiable, and complete records: Diameter, wall thickness, seam type, and grade.
3) *Material Properties Verification* – If any of the records required by paragraph 2), directly above, are not documented traceable, verifiable, and complete, the operator must obtain the missing records in accordance with Division 13.4 of this Plan. An operator must test the pipe materials cut out from the test manifold sites at the time the pressure test is conducted. If there is a failure during the pressure test, the operator must test any removed pipe from the pressure test failure in accordance with Division 13.4 of this Plan.

Method 2: Pressure Reduction – Reduce pressure, as necessary, and limit MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by the greater of 1.25 or the applicable class location factor in §192.619(a)(2)(ii). The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during a continuous 30-day period. The value used as the highest actual sustained operating pressure must account for differences between upstream and downstream pressure on the pipeline by use of either the lowest maximum pressure value for the entire pipeline segment or using the operating pressure gradient along the entire pipeline segment.
1) Where the pipeline segment has had a class location change in accordance with Division 13.6 of this Plan, and records documenting diameter, wall thickness, seam type, grade, and pressure tests are not documented in traceable, verifiable, and complete records, the operator must reduce the pipeline segment MAOP as follows:
   a) For pipeline segments where a class location changed from a Class 1 to Class 2, from Class 2 to Class 3, or from Class 3 to Class 4, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by 1.39 for Class 1 to Class 2, 1.67 for Class 2 to Class 3, and 2.00 for Class 3 to Class 4.
   b) For pipeline segments where a class location changed from Class 1 to Class 3, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019 divided by 2.00.
2) Future uprating of the pipeline segment in accordance with Division 12 of this Plan is allowed if the MAOP is established using Method 2.

(continued on next page)

3) If an operator elects to use Method 2, but desires to use a less conservative pressure reduction factor or longer look-back period, the operator must notify PHMSA in accordance with Division 2.8 of this Plan, no later than 7 calendar days after establishing the reduced NAOP. The notification must include the following details:
   a) Descriptions of the operational constraints, special circumstances, or other factors that preclude, or make it impractical, to use the pressure reduction factor specified in this Division;
   b) The fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis that complies with §192.712;
   c) Justification that establishing MAOP by another method allowed by this Division is impractical;
   d) Justification that the reduced MAOP determined by the operator is safe based on analysis of the condition of the pipeline segment, including material properties records, material properties verified in accordance with Division 13.4 of this Plan, and the history of the pipeline segment, particularly known corrosion and leakage, and the actual operating pressure, and additional compensatory preventive and mitigative measures taken or planned; and
   e) Planned duration for operating at the requested MAOP, long-term remediation measures and justification of this operating time interval, including fracture mechanics modeling for failure stress pressures and cyclic fatigue growth analysis and other validated forms of engineering analysis that have been reviewed and confirmed by subject matter experts.

Method 3: Engineering Critical Assessment (ECA) – Conduct an ECA in accordance with §192.632.

Method 4: Pipe Replacement – Replace the pipeline segment in accordance with this Plan.

Method 5: Pressure Reduction for Pipeline Segments with Small Potential Impact Radius – Pipelines with a potential impact radius (PIR) less than or equal to 150 feet may establish the MAOP as follows:
1) Reduce the MAOP to no greater than the highest actual operating pressure sustained by the pipeline during 5 years preceding October 1, 2019, divided by 1.1. The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during one continuous 30-day period. The reduced MAOP must account for difference between discharge and upstream pressure on the pipeline by use of either the lowest value for the entire pipeline segment or the operating pressure gradient.
2) Conduct patrols in accordance with §192.705 paragraphs (a) and (c) and conduct instrumented leakage surveys in accordance with §192.706 at intervals not to exceed those in the following table:

Class Locations	Patrols	Leakage Surveys
Class 1 and 2	3 ½ months, but at least four times each calendar year	3 ½ months, but at least four times each calendar year
Class 3 and 4	3 months, but at least six times each calendar year	3 months, but at least six times each calendar year

(continued on next page)

3) Under Method 5, future uprating of the pipeline segment in accordance with Division 12 of this Plan is allowed.

Method 6: Alternative Technology – Operators may use an alternative technical evaluation process that provides a documented engineering analysis for establishing MAOP. If an operator elects to use alternative technology, the operator must notify PHMSA in advance in accordance with Division 2.8 of this Plan. The notification must include the following details:

1) The technology or technologies to be used to tests, examinations, and assessments; the method for establishing material properties; and analytical techniques with similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the pipeline segment being evaluated;
2) Procedure and processes to conduct tests, examinations, assessments, and evaluation, analyze defects and flaws, and remediate defects discovered;
3) Pipeline segment data, including original design, maintenance and operating history, anomaly or flaw characterization;
4) Assessment techniques and acceptance criteria, including anomaly detection confidence level, probability of detection, and uncertainty of the predicted failure pressure quantified as a fraction of SMYS;
5) If any pipeline segment contains cracking or may be susceptible to cracking or crack-like defect found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with §192.712;
6) Operational monitoring procedures;
7) Methodology and criteria used to justify and establish the MAOP; and
8) Documentation of the operator's process and procedures used to implement the use of alternative technology, including any records generated through its use.

Records:

1) An operator must retain records of investigations test, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this Division for the life of the pipeline.

Additional Information:

1) This Plan does **NOT** include specific procedures for meeting the requirements of MAOP Reconfirmation on Steel Transmission Pipelines. If at any time an operator must meet the requirements of this Division, specific procedures must be developed and incorporated into this Plan.

Division 13.16: Odorization of Gas *(Reference 192.625)*

NOTE: See IAMU Procedure #8.1 - Odorization: Periodic Sampling and IAMU Procedure #8.0 - Odorization: Odorizer Inspection, Testing, and Preventative Maintenance for specific details.

1) Combustible gases in a distribution line must contain a natural odorant or be odorized so that at a concentration in air of 1/5 of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell.
2) After December 31, 1976 a combustible gas in a transmission line in a Class 3 or 4 location must comply with the requirements in paragraph 1) of this Division.
   a) At least 50% of the length of the line downstream from that location is in a Class 1 or Class 2 location.
   b) The line transports gas to any of the following facilities which received gas without an odorant from that line before May 5, 1975;
      i) An underground storage field;
      ii) A gas processing plant;
      iii) A gas dehydration plant; or
      iv) An industrial plant using gas in a process where the presence of an odorant:
         (1) Makes the end product unfit for the purpose for which it is intended;
         (2) Reduces the activity of a catalyst; or
         (3) Reduces the percentage completion of a chemical reaction.
   c) In the case of a lateral line which transports gas to a distribution center, at least 50% of the length of that line is in a Class 1 or Class 2 location; or
   d) The combustible gas is hydrogen intended for use as a feedstock in a manufacturing process.
3) In the concentrations in which it is used, the odorant in combustible gases must comply with the following:
   a) The odorant may not be deleterious to persons, materials, or pipe.
   b) The products of combustion from the odorant may not be toxic when breathed nor may they be corrosive or harmful to those materials to which the products of combustion will be exposed.
4) The odorant may not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight.
5) Equipment for odorization must introduce the odorant without wide variations in the level of odorant.
6) To assure the proper concentration of odorant in accordance with this Division, each operator must conduct periodic sampling of combustible gases (sniff tests) using an instrument capable of determining the % of gas in air at which the odor becomes readily detectable. Operators of master meter systems may comply with this requirement by –
   a) Receiving written verification from their gas source that the gas has the proper concentration of odorant; and
   b) Conducting perioding “sniff” tests at the extremities of the system to confirm the gas contains odorant.

(continued on next page)

Additional Information:

1) Periodic sampling of odor concentration (sniff tests) must be conducted at least 4 times per calendar year with intervals not exceeding 3 ½ months.
   a) **Reminder:** Odor sampling equipment must be calibrated according to the manufacturer's recommended procedures and a record of the calibration should be retained for as long as the equipment is being used for sampling.
2) Multiple sampling sites may be selected and designated throughout the system. The number of sampling sites varies with the type, size, flow rate, and configuration of the system. Enough samples must be taken at various locations to be able to ensure that all of the pipeline system is odorized at the required level.
3) Consideration should be given to the following potential factors when selecting sampling sites.
   a) Is the system primarily composed of steel or plastic pipeline?
   b) Does the configuration of the system include dead ends or is it a loop feed?
   c) Are there locations where testing should not be conducted due to environmental or manufacturing odors that could potentially mask the smell of the odorant during sampling?
   d) Does the selected location have very high or low gas flows?
   e) If distribution dead end main extends a sufficient distance past the last sampling location, will it be necessary to install a testing location?
4) Sniff test should be conducted by a person with a normal sense of smell.
   a) It may be necessary to periodically determine an individuals' "normal sense of smell" by using scratch-and-sniff cards to verify normal olfactory senses.
5) Sniff tests may be recorded and maintained on the Periodic Sampling of Odorant (Sniff Test) record and should be retained for a minimum of 10 years.

Determining Odorant Usage:

To ensure that odorization equipment is functioning and introducing odorant without wide variations, the amount of odorant being used or injected should be calculated and recorded at least 4 times per calendar year with intervals not exceeding 3 ½ months.

1) The Odorant Usage Report may be used to document and record odorant usage and the record should be retained for a minimum of 10 years.

Division 13.17: Tapping of Pipelines Under Pressure *(Reference 192.627)*

NOTE: Each tap made on a pipeline under pressure must be performed by a crew qualified to make hot taps.

Additional Information:

1) For specific details see the following procedures found in Part 7 of the Written Procedures Manual:
   a) IAMU Procedure #7.1: Tapping a Steel Pipeline – Tap Diameter 2" or Less
   b) IAMU Procedure #7.2: Tapping a Steel Pipeline – Tap Diameter Greater Than 2"
   c) IAMU Procedure #7.3: Tapping a Pipeline with a Built-in Cutter
2) Anytime hot tapping is going to be performed on a pipeline, the pressure rating of the tapping equipment or fitting should be verified prior to tapping.
3) Tap fittings should not be installed in any location on piping that shows signs of damage or corrosion that could affect the safe operation of the pipeline.

Division 13.18: Purging of Pipelines *(Reference 192.629)*

NOTE: See IAMU Procedure #7.5 - Purge: Flammable or Inert Gas for specific procedures on purging pipelines.

1) When a pipeline is being purged of air by use of gas, the gas must be released into one end of the line in a moderately rapid and continuous flow. If gas cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the gas.
2) When a pipeline is being purged of gas by use of air, the air must be released into one end of the line in a moderately rapid and continuous flow. If air cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the air.

Additional Information:

1) Purging of service lines that terminate indoors is not allowed unless the piping can be vented outdoors or the piping contains a pressure less than 1 psi where the volume of gas being purged will not accumulate and create a hazardous mixture.
   a) If purging indoor piping, it should be conducted through an appliance with a burner equipped with a continuous source of ignition and not in an area considered a confined space.
   b) If a continuous source of ignition is not available on an appliance, continual monitoring should be conducted using a combustible gas indicator and purging stopped when gas is detected.
2) If purging large volumes of gas or air from new installations or existing facilities, consideration should be given to notifying the affected public, public officials, and emergency officials before purging begins.

Division 13.19: Engineering Critical Assessment for MAOP Reconfirmation-Onshore Steel Transmission Pipelines *(Reference 192.632)*

When an operator conducts an MAOP reconfirmation according to Division 13.5 "Method 3" of this Plan, using an ECA to establish the material strength and MAOP of the pipeline segment, the ECA must comply with the requirements of this Division. The ECA must assess: threats, loadings operational circumstances relevant to those threats, including along the pipeline right-of-way; outcomes of the threat assessment; relevant mechanical and fracture properties; in-service degradation or failure processes; and initial and final defect size relevance. The ECA must quantify the interacting effects of threats on any defect in the pipeline.

ECA Analysis

1) The material properties required to perform an ECA analysis in accordance with this paragraph are as follows: diameter, wall thickness, seam type, grade, and Charpy v-notch toughness values based upon the lowest operational temperatures, if applicable. If any material properties required to perform and ECA for any pipeline segment in accordance with this paragraph are not documented traceable, verifiable, and complete, an operator must use conservative assumptions and include the pipeline segment in its program to verify the undocumented information in accordance with Division 13.4 of this Plan. The ECA must integrate, analyze, and account for the material properties, the results of all tests, direct examinations, destructive tests, and assessments performed in accordance with this Division, along with other pertinent information related to pipeline integrity, including close interval surveys, coating surveys, interference surveys required by Division 10 of this Plan, cause analyses of prior incidents, prior pressure test leaks and failures, other leaks, pipe inspections, and prior integrity assessments, including those required by §192.617, §192.710, and subpart O of 49 CFR Part 192.
2) The ECA must analyze and determine the predicted failure pressure for the defect being assessed using procedures that implement the appropriate failure criteria and justification as follows:
    a) The ECA must analyze any cracks or crack-like defects remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure of each defect in accordance with §192.712.
    b) The ECA must analyze any metal loss defects not associated with a dent, including corrosion, gouges, scrapes or other metal loss defects that could remain in the pipe, to determine the predicted failure pressure. AMSE/ANSI B31G or R-STRENG must be used for corrosion defects. Both procedures and their analysis apply to corroded regions that do not penetrate the pipe wall over 80% of the wall thickness and are subject to the limitations prescribed in the equations' procedures. The ECA must use conservative assumptions for metal loss dimensions (length, width, and depth).
    c) When determining the predicted failure pressure for gouges, crapes, selective seam weld corrosion, crack-related defects, or any defect within a dent, appropriate failure criteria and justification of the criteria must be used and documented.

(continued on next page)

    d) If SMYS or actual material yield and ultimate tensile strength is not known or not documented by traceable, verifiable, and complete records, then the operator must assume 30,000 psi or determine the material properties according to Division 13.4 of this Plan.
3) The ECA must analyze the interaction of defects to conservatively determine the most limiting predicted failure pressure. Examples include, but are not limited to, cracks in or near locations with corrosion metal loss, dents with gouges or other metal loss, or cracks in or near dents or other deformation damage. The ECA must document all evaluations and any assumptions used in the ECA process.
4) The MAOP must be established at the lowest predicted failure pressure for any known or postulated defect, or interacting defects, remaining in the pipe divided by the greater of 1.25 or the applicable factor listed in §192.619(a)(2)(ii).

Assessment to Determine Defect Remaining in Pipe:
An operator must utilize previous pressure tests or develop and implement an assessment program to determine the size of defects remaining in the pipe to be analyzed in accordance with the ECA Analysis section of this Division.

1) An operator may use a previous pressure test that complied with 49 CFR Part 192 subpart J to determine the defects remaining in the pipe if records for a pressure test meeting the requirements of 49 CFR Part 192 subpart J exist for the pipeline segment. The operator must predict how much the defects have grown since the date of the pressure test in accordance with §192.712. The ECA must analyze the predicted size of the largest defect that could have survived the pressure test and establish a re-assessment interval in accordance with the methodology in §192.712.
2) Operators may use an inline inspection program in accordance with the In-Line Inspection section of this Division.
3) Operators may use "other technology" if it is validated by a subject matter expert to produce an equivalent understanding of the condition of the pipe equal to or greater than pressure testing or an inline inspection program. If an operator elects to use "other technology" in the ECA, it must notify PHMSA in advance of using the other technology in accordance with Division 2.8 of this Plan. The "other technology" notification must include the following:
    a) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments, including characterization of defect size used in the crack assessments (length, depth, and volumetric); and
    b) Procedures and processes to conduct tests, examinations, assessments and evaluation, analyze defects, and remediate defects discovered.

In-Line Inspection:
An inline inspection (ILI) program to determine the defects remaining in the pipe for ECA analysis must be performed using tools that can detect wall loss, deformation from dents, wrinkle bends, ovalities, expansion, seam defects, including cracking and selective seam weld corrosion, longitudinal, circumferential and girth weld cracks, hard spot cracking, and stress corrosion cracking.

(continued on next page)

1) If a pipeline has segments that might be susceptible to hard spots based on assessment, leak, failure, manufacturing vintage history, or other information, then the ILI program must include a tool that and detect hard spots.
2) If the pipe has had a reportable incident as defined in Division 1.2 of this Plan, attributed to a girth weld failure since its most recent pressure test, then the ILI program must include a tool that can detect girth weld defects unless ECA analysis performed in accordance with this Division includes engineering evaluation program to analyze and account for the susceptibility of girth weld failure due to lateral stresses.
3) Inline inspection must be formed in accordance with §192.493.
4) An operator must use unity plots or equivalent methodologies to validate the performance of the ILI tools in identifying and sizing actionable manufacturing and construction related anomalies. Enough data points must be used to validate tool performance at the same or better statistical confidence level provided in the tool specifications. The operator must have a process for identifying defects outside the tool performance specifications and following up with the ILI vendor to conduct additional in-field examinations, reanalyze ILI data, or both.
5) Interpretation and evaluation of assessment results must meet the requirements of §192.710, §192.713, and 49 CFR Part 192 subpart O, and must conservatively account for the accuracy and reliability of ILI, in-the-ditch examination methods and tools, and any other assessment and examination results used to determine the actual sizes of cracks, metal loss, deformation and other defect dimensions by applying the most conservative limit of the tool tolerance specification. ILI and in-the-ditch examination tools and procedures for crack assessments (length and depth) must have performance and evaluation standards confirmed for accuracy through confirmation tests for the defect types and pipe material vintage being evaluated. Inaccuracies must be accounted for in the procedures for evaluations and fracture mechanics models for predicted failure pressure determinations.
6) Anomalies detected by ILI assessments must be remediated in accordance with criteria listed in §192.713 and §192.933.

Defect Remaining Life

If any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with §192.712.

Records:

An operator must retain records of investigations, test, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this Division for the life of the pipeline.

CITY OF BLOOMFIELD, IOWA

DIVISION FOURTEEN

Maintenance

49 CFR Part 192 Subpart M

Division 14.1: Scope *(Reference 192.701)*

This Division prescribes the minimum requirements for maintenance of pipeline facilities.

Division 14.2: General *(Reference 192.703)*

1) No person may operate a segment of pipeline, unless it is maintained in accordance with this Division.
2) Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service.
3) Hazardous leaks must be repaired promptly.

Division 14.3: Transmission Pipelines - Patrolling *(Reference 192.705)*

NOTE: See IAMU Procedure #10.4 - Inspect Pipeline Surface Conditions: Patrol Right-of-Way or Easement for specific details on completing pipeline patrols.

1) Each operator shall have a patrol program in place to observe surface conditions on an adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation.
2) The frequency of patrols is determined by the size of the line, the operating pressures, the class location, terrain, weather, and other relevant factors. The required intervals for conducting patrols are listed in the following table:

Class location of pipeline	**Maximum interval between patrols**	
	At highway and railroad crossings	**At all other locations**
1 and 2	At least twice each calendar year not exceeding 7 ½ months	At least once each calendar year not exceeding 15 months
3	At least 4 times each calendar year not exceeding 4 ½ months	At least twice each calendar year not exceeding 7 ½ months
4	At least 4 times each calendar year not exceeding 4 ½ months	At least 4 times each calendar year not exceeding 4 ½ months

3) Methods of patrolling include walking, driving, flying or other appropriate means of traversing the right-of-way.

Additional Information:

1) All required patrols must be recorded and retained for a minimum of 5 years from the date the patrol was conducted.
2) Patrols may be documented on the Pipeline Patrol Record or another company approved document that contains the required information.

Division 14.4: Transmission Pipelines – Leak Surveys *(Reference 192.706)*

NOTE: For specific written procedures, see IAMU Procedure #10.3 - Walking Leakage Survey.

1) Leakage surveys must be conducted on transmission pipelines using leak detection equipment at least once each calendar year with intervals not exceeding 15 months.
2) If a transmission line, transports gas according to Division 13.16 without an odor or odorant, leakage surveys must be conducted with leak detection equipment according to the following:
   a) In Class 3 locations, at least twice each calendar year with intervals not exceeding 7 ½ months.
   b) In Class 4 locations, at least 4 times each calendar year with intervals not exceeding 4 ½ months.

Additional Information:

1) Leak detection equipment used to conduct leak surveys on transmission facilities must be calibrated prior to conducting the survey.
2) Required leakage surveys must be documented and retained for a minimum of 10 years.
3) Leak surveys may be documented and retained on the Leak Survey Record or other company approved document containing all the required information.

Division 14.5: Line Markers for Mains and Transmission Lines *(Reference 192.707)*

NOTE: See IAMU Procedure #8.5 - Install and Maintain Pipeline Markers for specific details.

Buried Pipelines:

1) A line marker must be placed and maintained as close as practical over each buried main and transmission line at the following locations:
   a) At each crossing of a public road and railroad; and
   b) Wherever necessary to identify the location of the transmission line or main to reduce the possibility of damage or interference.

Exceptions for Buried Pipelines:

1) Line markers are NOT required for the following pipeline locations:
   a) Mains and transmission lines located offshore, or at crossings of or under waterways and other bodies of water.
   b) Mains in Class 3 or 4 locations where a damage prevention program is in effect according to Division 13.8 of this Plan.
   c) Transmission lines in Class 3 or 4 locations until March 20, 1996.
   d) Transmission lines in Class 3 or 4 locations where the placement of a line marker is impractical.

Aboveground Pipelines and Facilities:

1) Line markers must be placed and maintained along each section of a main and transmission line that is located aboveground in an area accessible to the public.

Marking Requirements:

1) The following information must be written legibly on a background of sharply contrasting color on each line marker:
   a) The word "Warning", "Caution", or "Danger" must be in letters at least 1" high with a ¼" stroke.
   b) Type of gas being transported (Natural Gas Pipeline) must be in letters at least 1" high with a ¼" stroke.
   c) The name of the operator.
   d) Telephone number (including area code) where the operator can be reached at all times.
   e) The One-Call telephone number (811) for locate requests.

Additional Information:

1) It is recommended that tri-view markers are selected for use to allow for ease of identification.
2) In rural areas, consideration should be given to installing line makers in locations where you have a sight line from one marker to the next.
3) Examples of aboveground facilities that also require markers/signage are take point locations, regulator stations, casing vents, and hairpin valves.

Division 14.6: Transmission Lines – Recordkeeping *(Reference 192.709)*

Operators must maintain the following records for transmission lines for the specified periods of time listed below.

1) The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for the life of the pipeline.
2) The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 5 years. However, repairs generated patrols, surveys, inspections, or tests required by Divisions 13 and 14 of this Plan must be retained in accordance with paragraph 3) listed below.
3) A record of each patrol, survey, inspection, and test required by Divisions 13 and 14 of this Plan must be retained for at least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.

Division 14.7: Transmission Lines – Assessments Outside of High Consequence Areas *(Reference 192.710)*

Applicability: This Division applies to onshore steel transmission pipeline segments with a MAOP greater than or equal to 30% of SMYS and are located in the following locations.

1) A Class 3 or 4 location; or
2) A moderate consequence area as defined in Division 2.1 of this Plan, if the pipeline segment can accommodate inspection by means of an instrumented inline inspection tool.
3) This Division does NOT apply to pipeline segments located in high consequence areas.

Assessments:

Initial Assessment:

1) An operator must perform initial assessments in accordance with this Division based on a risk-based prioritization schedule and complete initial assessment for all applicable pipeline segments no later than July 3, 2034, or as soon as practicable but not to exceed 10 years after the pipeline segment first meets the conditions of the Applicability section of this Division (due to a change in class location or the area becomes a moderate consequence area), whichever is later.

Periodic Reassessment:

1) An operator must perform periodic reassessments at least once every 10 years, with intervals not to exceed 126 months, or a shorter reassessment interval based upon the type of anomaly, operational, material, and environmental conditions found on the pipeline segment, or as necessary to ensure public safety.

Prior Assessment:

1) An operator may use a prior assessment conducted before July 1, 2020 as an initial assessment for the pipeline segment, if the assessment met the requirements of 49 CFR Part 192 for inline inspection at the time of the assessment. If an operator uses this prior assessment as its initial assessment, the operator must reassess the pipeline segment according to the reassessment interval specified in paragraph 1) of the Initial Assessment section of this Division.

MAOP Verification:

1) An integrity assessment conducted in accordance with the requirements of Division 13.15 of this Plan for establishing MAOP may be used as an initial assessment or reassessment under this Division.

Assessment Method: The initial assessments and the reassessments required by the Assessments section of this Division must be capable of identifying anomalies and defects associated with each of the threats to which the pipeline segment is susceptible and must be performed using one or more of the following methods:

Internal Inspection:

1) Internal inspection tool or tools capable of detecting those threats to which the pipeline is susceptible, such as corrosion, deformation and mechanical damage, material cracking and crack-like defects, hard spots with cracking, and any other threats to which the covered segment is susceptible. Inline inspections must be conducted according to Division 10.25.

(continued on next page)

Pressure Test:

1) Pressure test conducted in accordance with Division 11 of this Plan is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms; manufacturing and related defect threats, including defective pipe and pipe seams; and stress corrosion cracking, selective seam weld corrosion, dents and other forms of mechanical damage.

Spike Hydrostatic Pressure Test:

1) A spike hydrostatic pressure test conducted in accordance with Division 11.4 is appropriate for time-dependent threats such as stress corrosion cracking; selective seam weld corrosion; manufacturing and relate defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects.

Direct Examination:

1) Excavation and "in situ" direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all applicable threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), Inverse Wave Field Extrapolation (IWEX), radiography, and magnetic particle inspection (MPI).

Guided Wave Ultrasonic Testing:

1) Guided wave ultrasonic testing must be conducted as described in Appendix F of 49 CFR Part 192.

Direct Assessment:

1) The use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with the applicable requirements specified in §192.925, §192.927, and §192.929.

Other Technology:

1) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify PHMSA in advance of using the other technology in accordance with Division 2.8 of this Plan.

Data Analysis: An operator must analyze and account for the data obtained from an assessment performed according to the Assessment Method section of this Division to determine if a condition could adversely affect the safe operation of the pipeline using personnel qualified by knowledge, training, and experience. In addition, when analyzing inline inspection data, an operator must account for uncertainties in reported results in identifying and characterizing anomalies.

Discovery of Condition: Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that 180 days is impracticable.

(continued on next page)

Remediation: An operator must comply with the requirements in §192.485, §192.711, and §192.713, where applicable, if a condition that could adversely affect the safe operation of a pipeline is discovered.

Analysis of Information: An operator must analyze and account for all available relevant information about a pipeline in complying with all of the requirements in this Division.

Division 14.8: Transmission Lines – General Requirements for Repair Procedures *(Reference 192.711)*

Temporary Repairs:

1) Operators must take immediate temporary measures to protect the public whenever:
   a) A leak, imperfection, or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above 40% of the SMYS; and
   b) It is not feasible to make a permanent repair at the time of discovery.

Permanent Repairs:

1) Operators must make permanent repairs on its pipeline system according to the following.
   a) Non-integrity management repairs – operator must make permanent repairs as soon as feasible.
   b) Integrity management repairs – when an operator discovers a condition on a pipeline covered under 49 CFR Part 192 Subpart O, the operator must remediate the condition as prescribed by §192.933(d).

Welded Patch:

1) Except as provided in §192.717(b)(3), operators may not use weld patches as a means of repair.

Division 14.9: Transmission Lines – Analysis of Predicted Failure Pressure

(Reference 192.712)

1) **Applicability:**
   a) Whenever required by this Plan, operators of onshore steel transmission pipelines must analyze anomalies or defects to determine the predicted failure pressure at the location of the anomaly or defect, and the remaining life of the pipeline segment at the location of the anomaly or defect, in accordance with this Division.
2) **Corrosion Metal Loss:**
   a) When analyzing corrosion metal loss under this Division, an operator must use a suitable remaining strength calculation method including, ASME/ANSI B31G, R-STRENG, or an alternative equivalent method of remaining strength calculation that will provide and equally conservative result.
3) **RESERVED**
4) **Cracks and Crack-like Defects:**
   a) *Crack Analysis Models* – When analyzing cracks and crack-like defects under this Division, an operator must determine predicted failure pressure, failure stress pressure, and crack growth using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both), material properties (pipe and weld properties), and boundary condition used (pressure test, ILI, or other).
   b) *Analysis for Crack Growth and Remaining Life* – If the pipeline segment is susceptible to cyclic fatigue or other loading conditions that could leak to fatigue crack growth, fatigue analysis must be performed using an applicable fatigue crack growth law (Paris Law) or other technically appropriate engineering methodology. For other degradation processes that can cause crack growth, appropriate engineering analysis must be used. The above methodologies must be validated by a subject matter expert to determine conservative predictions of flaw growth and remaining life at the MAOP. The operator must calculate the remaining life of the pipeline by determining the amount of time required for the crack to grow to a size that would fail at MAOP.
      i) When calculating crack size that would fail at MAOP, and the material toughness is not documented in traceable, verifiable, and complete records, the same Charpy v-notch toughness value established in paragraph 5) b) of this Division must be used.
      ii) Initial and final flaw size must be determined using a fracture mechanics model appropriate to the failure mode (ductile, brittle, or both) and boundary condition used (pressure test, ILI, or other).
      iii) An operator must re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated by this analysis has expired. The operator must determine and document if further pressure tests or use of other assessment methods are required at that time. The operator must continue to re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated in the most recent evaluation has expired.

(continued on next page)

c) *Cracks That Survive Pressure Testing* – For cases in which the operator does not have in-line inspection crack anomaly data and is analyzing potential crack defects that could have survived a pressure test, the operator must calculate the largest potential crack defect sizes using methods in paragraph 4) a) of this Division. If pipe material toughness is not documented in traceable, verifiable, and complete records, the operator must use one of the following for Charpy v-notch toughness values based upon minimum operational temperature and equivalent to a full-size specimen value:
    i) Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;
    ii) A conservative Charpy v-notch toughness value to determine the toughness based upon the material properties verification process specified in Division 13.4 of this Plan;
    iii) A full size equivalent Charpy v-notch upper-shelf toughness level of 120 ft/lbs; or
    iv) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of the crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in accordance with Division 2.8 of this Plan.

5) **Data:**
  a) In performing the analyses of predicted or assumed anomalies or defects in accordance with this Division, an operator must use data as follows:
    i) An operator must explicitly analyze and account for uncertainties in reported assessment results in identifying and characterizing the type and dimensions of anomalies or defects used in the analyses, unless the defect dimensions have been verified using "in situ" direct measurements.
    ii) The analyses performed in accordance with this section must utilize pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis is not available, an operator must obtain the undocumented data through Division 13.4 of this Plan. Until documented material properties are available, the operator shall use conservative assumptions as follows:
      (1) *Material Toughness* – An operator must one of the following for material toughness:
        (a) Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;
        (b) A conservative Charpy v-notch toughness value to determine the toughness based upon the ongoing material properties verification process specified in Division 13.4 of this Plan.
        (c) If the pipeline segment has a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 5.0 ft/lbs for body cracks and 1 ft/lbs for cold weld, lack of fusion, and selective seam weld corrosion; or
        (d) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in advance according Division 2.8 of this Plan.

(continued on next page)

(2) *Material Strength* – An operator must assume one of the following for material strength:
   (a) Grade A pipe (30,000 psi), or
   (b) The specified minimum yield strength that is the basis for the current maximum allowable operating pressure.

(3) *Pipe Dimensions and Other Data* – Until pipe wall thickness, diameter, or other data are determined and documented in accordance with Division 2.8 of this Plan, the operator must use values upon which the current MAOP is based.

6) **Review:** Analyses conducted in accordance with this Division must be reviewed and confirmed by a subject matter expert.
7) **Records:** An operator must keep for the life of the pipeline records of the investigations, analyses, and other actions taken in accordance with the requirements of this Division. Records must document justifications, deviations, and determinations made for the following, as applicable:
   a) The technical approach used for the analysis;
   b) All data used and analyzed;
   c) Pipe and weld properties;
   d) Procedures used;
   e) Evaluation methodology used;
   f) Models used;
   g) Direct "in situ" examination data;
   h) In-line inspection tool run information evaluated, including any multiple in-line inspection tool runs;
   i) Pressure test data and results
   j) In-the-ditch assessments;
   k) All measurement tool, assessment, and evaluation accuracy specifications and tolerances used in technical and operational results;
   l) All finite element analysis results;
   m) The number of pressure cycles to failure, the equivalent number of annual pressure cycles, and the pressure cycle counting method;
   n) The predicted fatigue life and predicted failure pressure from the required fatigue life models and fracture mechanics evaluation methods;
   o) Safety factors used for fatigue life and/or predicted failure pressure calculations;
   p) Reassessment time interval and safety factors;
   q) The date of the review;
   r) Confirmation of the results by qualified technical subject matter experts; and
   s) Approval by responsible operator management personnel.

Division 14.10: Transmission Lines – Permanent Field Repair of Imperfections and Damages *(Reference 192.713)*

1) Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40% SMYS must be repaired according to the following:
   a) Removed by cutting out and replacing a cylindrical piece of pipe; or
   b) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.
2) Operating pressure must be at a safe level during repair operations.

Division 14.11: Transmission Lines – Permanent Field Repair of Welds *(Reference 192.715)*

Each weld that is unacceptable according to §192.241(c) must be repaired as follows:

1) If it is feasible to take the segment of transmission line out of service, the weld must be repaired in accordance with the applicable requirements of §192.245.
2) A weld may be repaired in accordance with §192.245 while the segment of transmission line is in service if:
   a) The weld is not leaking;
   b) The pressure in the segment is reduced so that it does not produce a stress that is more than 20% of the SMYS of the pipe; and
   c) Grinding of the defective area can be limited so that at least 1/8" thickness in the pipe weld remains.
3) A defective weld which cannot be repaired in accordance with paragraph 1) or 2) of this Division must be repaired by installing a full encirclement welded split sleeve of appropriate design.

Additional Information:

1) The requirements of §192.241 and §192.245 can be found in the IAMU Model Gas Distribution Pipeline Welding Procedures Manual.
2) See IAMU Procedure #8.10 - Fit-up of Weld Type Repair Sleeves for additional details.

Division 14.12: Transmission Lines – Permanent Field Repair of Leaks *(Reference 192.717)*

Each permanent field repair of a leak on a transmission line must be made by the following methods:

1) Removing the leak by cutting out and replacing a cylindrical piece of pipe; or
2) Repairing the leak by one of the following methods:
    a) Install a full encirclement welded split sleeve of appropriate design, unless the transmission line is joined by mechanical couplings and operates at less than 40% SMYS.
    b) If the leak is due to a corrosion pit, install a properly designed bolt-on-leak clamp.
    c) If the leak is due to a corrosion pit and on pipe of not more than 40,000 psi SMYS, fillet weld over the pitted area a steel plate patch with rounded corners, of the same or greater thickness than the pipe, and not more than one-half of the diameter of the pipe in size.
    d) If the leak is on a submerged offshore pipeline or submerged pipeline in inland navigable waters, mechanically apply a full encirclement split sleeve of appropriate design.
    e) Apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

Additional Information:

1) See IAMU Procedure #8.10 - Fit-up of Weld Type Repair Sleeves or IAMU Procedure #8.8 - Install Mechanical Clamps or Sleeves: Bolted, for additional details.

Division 14.13: Transmission Lines – Testing of Repairs *(Reference 192.719)*

Testing of Replacement Pipe:

1) If a segment of transmission line is repaired by cutting out the damaged portion of the pipe as a cylinder, the replacement pipe must be tested to the pressure required for a new line installed in the same location. This test may be made on the pipe before it is installed.

Testing of Repairs Made by Welding:

1) Each repair made by welding in accordance with this Division must be examined in accordance with §192.241.

Additional Information:

1) Procedures for pressure testing replacement segments of transmission line pipe can be found in IAMU Procedure #5.1 – Pressure Test: MAOP Less Than 100 psi or IAMU Procedure #5.2 – Pressure Test: MAOP Greater Than or Equal to 100 psi.

Division 14.14: Distribution Systems – Leak Repairs *(Reference 192.720)*

As of January 22, 2019, mechanical leak repair clamps may not be used as permanent repair method on plastic pipe.

Additional Information:

1) See IAMU Procedure #8.8 - Install Mechanical Clamps and Sleeves for specific details on installing leak clamps on pipelines.

Division 14.15: Distribution Systems – Patrolling *(Reference 192.721)*

NOTE: See IAMU Procedure #10.4 - Inspect Pipeline Surface Conditions: Patrol Right-of-Way or Easement for specific details on completing pipeline patrols.

1) 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.
2) Mains in places or on structures where anticipated physical movement or external load forces could cause failure or leakage must be conducted at the frequencies found in the following table:

Location	Frequency
Inside Business Districts	At least four times each calendar year with intervals not exceeding 4 ½ months
Outside Business Districts	At least twice each calendar year with intervals not exceeding 7 ½ months

Additional Information:

1) All required patrols must be recorded and retained for a minimum of 5 years from the date the patrol was conducted.
2) Patrols may be documented on the Pipeline Patrol Record or another company approved document that contains the required information.
3) Consideration should be given to the following locations to identify facilities that may need to be patrolled:
   a) Casings with or without vents.
   b) Bridge hangs.
   c) Water crossings (creeks or rivers).
   d) Excavations or areas with known high levels of construction.
   e) State or Federal highway crossings.
   f) Railroad crossings.
   g) Areas prone to erosion.

Division 14.16: Distribution Systems – Leak Surveys *(Reference 192.723)*

NOTE: For specific written procedures, see IAMU Procedure #10.3 - Walking Leakage Survey.

1) Operators of a distribution system must conduct leakage surveys in accordance with this Division.
2) The type and scope of the leakage survey program must be determined by the nature of the operations and the local conditions, but must meet the following minimum requirements:

Business District Leak Surveys:

1) A leak survey using leak detection equipment must be conducted in business districts at least once each calendar year with intervals not exceeding 15 months.
2) The leak survey must include testing 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.

Outside of Business District Leak Surveys:

1) A leak survey using leak detection equipment must be conducted on all distribution facilities outside of the business district at a minimum of at least once every 5 years with intervals not exceeding 63 months.
2) If an operator's system includes cathodically unprotected distribution lines on which an electrical survey for corrosion is impractical, a leak survey must be conducted at least once every 3 years with intervals not exceeding 39 months.

Additional Information:

1) Leak detection equipment used to conduct leak surveys on distribution facilities must be calibrated prior to conducting the survey.
2) Required leakage surveys must be documented and retained for a minimum of 10 years.
3) Leak surveys may be documented and retained on the Leak Survey Record or other company approved document containing all the required information.
4) When defining business districts, consideration should be given to the following:
   a) Higher population areas in comparison to the rest of the system.
   b) Areas where the majority of the pipelines are located under continuous wall-to-wall paved surfaces.
   c) Schools, churches, hospitals, care facilities, apartment complexes, industrial/commercial complexes, financial centers, or any other areas where the public regularly congregates.

Division 14.17: Test Requirements for Reinstating Service Lines *(Reference 192.725)*

NOTE: See IAMU Procedure #5.1 – Pressure Test: MAOP Less Than 100 psi for specific details on how to complete tests for reinstating service lines.

1) Except as provided in the paragraph below, each disconnected service line must be tested in the same manner as a new service line, before being reinstated.
2) 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 installing a bypass, any part of the original service line used to maintain continuous service need not be tested.

Additional Information:

1) All pressure tests for reinstating service lines must be documented and retained for the life of the pipeline.
2) The Pipeline Installation Report or other company approved document may be used to record and retain the required information.

Division 14.18: Abandonment or Deactivation of Facilities *(Reference 192.727)*

NOTE: See IAMU Procedure #8.13 - Abandon/Deactivate Mains, IAMU Procedure #8.14 - Abandon/Deactivate Service Lines for specific details.

1) Operators must conduct abandonment or deactivation of pipelines according to the requirements found in this Division.
2) Each pipeline abandoned in place must be disconnected from all sources and supplies of gas, purged of gas, 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.
3) Except for service lines, each inactive pipeline that is not being maintained under this Plan must be disconnected from all sources and supplies of gas, purged of gas, 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.
4) Whenever service to a customer is discontinued, one of the following methods must be complied with:
   a) 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 persons other than those authorized by the operator.
   b) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.
   c) The customer's piping must be physically disconnected from the gas supply and open ends of the pipe sealed.
5) If air is used for purging, the operator shall ensure that a combustible mixture is not present after purging.
6) Each abandoned vault must be filled with a suitable compacted material.

Additional Information:

1) A pipeline that is disconnected from the source of gas or the gas supply and is physically removed from the ground, is not considered abandoned.
2) A record must be retained for all abandoned pipelines.
3) The Abandoned Pipeline Report or other company approved document may be used to record and retain the required information.

Division 14.19: Pressure Limiting and Regulating Stations - Inspection and Testing *(Reference 192.739)*

NOTE: The following procedures for specific details for inspection and testing of pressure regulating and pressure limiting devices.

- IAMU Procedure #9.0 - Spring-Loaded, Pressure Regulating Device: Inspection and Testing, Preventive and Corrective Maintenance
- IAMU Procedure #9.1 - Pilot-Operated, Pressure Regulating Device: Inspection and Testing, Preventive and Corrective Maintenance
- IAMU Procedure #9.2 - Spring-Loaded, Pressure Limiting Device: Inspection and Testing, Preventive and Corrective Maintenance
- IAMU Procedure #9.3 - Pilot-Operated, Pressure Limiting Device: Inspection and Testing, Preventive and Corrective Maintenance

1) Each pressure limiting station, relief device (except for rupture discs), and pressure regulating station and its equipment must be inspected and tested at least once each calendar year with intervals not exceeding 15 months to determine the following:
   a) In good mechanical condition;
   b) Adequate from the standpoint of capacity and reliability of operation for the service in which it is intended;
   c) Set to control or relieve at the correct pressures consistent with the pressure limits of Division 5.21 of this Plan; and
   d) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.
2) For steel pipelines whose MAOP is determined under §192.619(c), if the MAOP is 60 psi or more, the control or relief pressure limit is as follows:

If the MAOP produces a hoop stress that is:	Then the pressure limit is:
Greater than 72% SMYS	MAOP plus 4%
Unknown % of SMYS	A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP

Additional Information:

1) Piping supports/hangers found at the station should also be examined to ensure that proper support is being provided.
2) Locking devices on station gates, valves, covers, etc., should be inspected for location and proper operation.
3) Signage should be inspected for proper location, content, and fading.
4) Regulator station inspections must be documented and retained for at least 10 years and may be recorded on the Regulator Station Inspection Record or another company approved document containing the required information.
5) If gas supplier performs regulation for the operator, the suppliers' records must be obtained.

Division 14.20: Pressure Regulating, Limiting and Overpressure Protection – Farm Taps (Service Lines Off of Transmission Pipelines) *(Reference 192.740)*

NOTE: This Division applies ONLY to service lines directly connected to transmission pipelines (farm taps).

1) Each pressure regulating or limiting device, relief device (except for rupture discs), automatic shut-off device, and associated equipment found on farm taps must be inspected and tested at least once every 3 calendar years with intervals not exceeding 39 months to determine the following:
   a) In good mechanical condition;
   b) Adequate from the standpoint of capacity and reliability of operation for the service in which it was intended;
   c) Set to control or relieve at the correct pressure consistent with the pressure limits of Division 5.19 of this Plan, and to limit the pressure on the inlet side of the service regulator to 60 psi or less in case the upstream regulator fails to function properly; and
   d) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.
2) This Division does not apply to the following:
   a) Equipment installed on service lines that only serve engines that power irrigation pumps.
   b) Farm taps that have been included in a Distribution Integrity Management Plan (DIMP) meeting the requirements of 49 CFR Part 192 Subpart P; or
   c) A service line directly connected either a production or gathering pipeline other than a regulated gathering line.

Additional Information:
1) All farm tap inspections and testing must be documented and retained for a minimum of 5 years.
2) The Farm Tap Inspection Record or other company approved document may be used to record and retain the required information.
3) If including farm tap service lines into DIMP so that inspection and test is NOT required, consideration should be given to conducting inspection and testing of farm tap equipment as often as necessary to ensure it is functioning correctly.

Division 14.21: Pressure Limiting and Regulating Stations – Telemetering and Recording Gauges *(Reference 192.741)*

1) Each distribution system supplied by more than one district regulator station must be equipped with telemetering or recording pressure gauges to indicate the gas pressure in the district.
2) On distribution systems supplied by a single district regulator station, the operator shall determine the necessity of installing telemetering or recording gauges in the district, taking into consideration the number of customers supplied, the operating pressures, the capacity of the installation, and other operating conditions.
3) If there are indications of abnormally high or low pressure, the regulator and the auxiliary equipment must be inspected and the necessary measures employed to correct any unsatisfactory operating conditions.

Additional Information:

1) Instruments used for telemetering and recording pressures should be inspected and tested according to the manufacturer's recommended practices and procedures for that specific instrument.
2) If pressure gauges, without recorders, are used to monitor pressures, consideration should be given to visually confirming and recording the operating pressures at least once per day.
   a) During abnormally high demand periods (extreme cold), pressures should be monitored as frequently as necessary to determine if pipeline pressure is decreasing below desired pressures due to flow demands.

Division 14.22: Pressure Limiting and Regulating Stations – Capacity of Relief Devices *(Reference 192.743)*

NOTE: The capacity of pressure limiting and regulator stations is included on the Regulator Station Inspection Record.

1) Pressure relief devices at pressure limiting stations and pressure regulating stations must have sufficient capacity to protect the facilities to which they are attached. The capacity must be consistent with the requirements of Division 5.21 of this Plan. This capacity must be determined at least once each calendar year with intervals not exceeding 15 months, by testing the device in place or by review and calculations.
2) 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, additional calculations DO NOT need to be made if the annual review documents that the parameters have not changed to cause the related or experimentally determined relieving capacity to be insufficient.
3) If a relief device is found insufficient in capacity, a new or additional device must be installed to provide the capacity required by paragraph 1) of this Division.

Additional Information:

1) Documentation of the capacity calculations should be retained for as long as that specific device is being used.
   a) If at any time, the pressure regulating or pressure limiting device is replaced with a new device or if internal components have changed that affect the capacity of the pressure regulating or pressure limiting device, a re-calculation of capacities must be made.
2) Consideration should be given to conducting capacity calculations and annual reviews at the same time as the inspection and testing of the regulator station devices.
3) The capacities of pressure regulating and pressure limiting devices may be documented on the Regulator Station Inspection Record or other company approved document.

Division 14.23: Valve Maintenance – Transmission Pipelines *(Reference 192.745)*

NOTE: See the following procedure for specific details on the operation and maintenance of valves.

- IAMU Procedure #9.4 - Manually Opening and Closing Valves
- IAMU Procedure #9.5 - Valve: Visual Inspection and Partial Operation
- IAMU Procedure #9.6 - Valve: Preventative & Corrective Maintenance
- IAMU Procedure #9.7 - Inspect Emergency Valves

1) Each transmission line valve that might be required during an emergency must be inspected and partially operated at least once each calendar year with intervals not exceeding 15 months.
2) Operator's must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.

Additional Information:

1) Partial operation of a transmission line valve is defined as operating the valve at least 1/8th of turn.
2) Consideration should be given to flow conditions in the pipeline when inspecting and partially operating valves.
3) If a valve is found inoperable and another valve cannot be designated as its replacement, repairs must be made to allow operation of the valve, or the valve must be replaced.
4) Documentation of transmission line valve inspection and maintenance may be retained on the Valve Inspection and Maintenance Record or other company approved document.
   a) Records must be retained for a minimum of 10 years.

Division 14.24: Valve Maintenance – Distribution Systems *(Reference 192.747)*

NOTE: See the following procedure for specific details on the operation and maintenance of valves.

- IAMU Procedure #9.4 - Manually Opening and Closing Valves
- IAMU Procedure #9.5 - Valve: Visual Inspection and Partial Operation
- IAMU Procedure #9.6 - Valve: Preventative & Corrective Maintenance
- IAMU Procedure #9.7 - Inspect Emergency Valves

1) Each valve that may be necessary for the safe operation of the distribution system (emergency valves), must be checked and serviced at least once each calendar year with intervals not exceeding 15 months.
2) Operator's must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve that will provide a similar level of effectiveness for isolating the desired area.

Additional Information:

1) This Plan requires that distribution valve maintenance include partial operation just as transmission line valves.
2) Partial operation of a distribution line valve is defined as operating the valve at least 1/8th of turn.
3) Consideration should be given to flow conditions in the pipeline when inspecting and partially operating valves.
4) If a valve is found inoperable and another valve cannot be designated as its replacement, repairs must be made to allow operation of the valve, or the valve must be replaced.
5) Documentation of distribution line valve inspection and maintenance may be retained on the Valve Inspection and Maintenance Record or other company approved document.
    a) Records must be retained for a minimum of 10 years.

Division 14.25: Vault Maintenance *(Reference 192.749)*

1) Each vault housing pressure regulating and pressure limiting equipment, and having a volumetric internal content of 200 cubic feet or more, must be inspected at least once each calendar year with intervals not exceeding 15 months to determine that it is good physical condition and adequately vented.
2) If gas if found in the vault, the equipment in the vault must be inspected for leaks, and any leaks found, must be repaired.
3) The ventilating equipment must also be inspected to determine that it is functioning properly.
4) Each vault cover must be inspected to assure that it does not present a hazard to public safety.

Additional Information:

1) See IAMU Procedure #8.21 – Vault Maintenance for specific details.
2) For operators who have pressure regulating or pressure limiting "pits" that do not meet the requirements to be considered a vault, consideration may be given to the following inspection and/or maintenance items:
   a) Inspect the pit cover/lid to ensure that it is in good shape and can handle any anticipated external loads.
   b) Prior to entry into the pit, the operator should check the atmosphere with a combustible gas indicator to ensure that a hazardous condition does not exist.
   c) Leak check all piping and components using a combustible gas indicator or leak detection solution. If any leaks are found, they must be repaired.
   d) The walls of the pit should be inspected for signs of damage, cracking, or cave-ins.
   e) The entry and exit points of piping into and out of the pit should be inspected to ensure that the walls of the pit are not placing undue strain on the pipe and/or causing damage to the pipe or pipe coating.
   f) If applicable, inspect all pipe supports for proper engagement.
   g) All piping should be inspected for signs of corrosion and if corrosion with metal loss is discovered, remedial action must take place.
3) The required vault maintenance may be recorded on the Vault Inspection and Maintenance Record or other company approved document.

Division 14.26: Launcher and Receiver Safety *(Reference 192.750)*

1) Any launcher or receiver used after July 1, 2021, must be equipped with a device capable of safely relieving pressure in the barrel before removal or opening of the launcher or receiver barrel closure or flange and insertion or removal of in-line inspection tools, scraper, or spheres.
2) An operator must use a device to either: Indicate that pressure has been relieved in the barrel; or alternatively prevent opening of the barrel closure or flange when pressurized, or insertion or removal of in-line devices, if pressure has not been relieved.

Division 14.27: Prevention of Accidental Ignition *(Reference 192.751)*

NOTE: See IAMU Procedure #8.15 - Prevent Accidental Ignition for specific procedures.

1) Operator's must take steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion, including the following:
    a) When a hazardous amount of gas is being vented into open air, each potential source of ignition must be removed from the area and fire extinguisher must be provided.
    b) Gas or electric welding or cutting may not be performed on pipe or pipeline components that contain a combustible mixture of gas and air in the area of work.
    c) Post warning signs, where appropriate.

Division 14.28: Caulked Bell and Spigot Joints *(Reference 192.753)*

NOTE: This Plan does NOT provide specific procedures for making or repairing caulked bell and spigot joints.

1) Each cast iron caulked bell and spigot joint that is subject to pressures of more than 25 psi must be sealed with:
   a) A mechanical leak clamp; or
   b) A material device which:
      i) Does not reduce the flexibility of the joint;
      ii) Permanently bonds, either chemically or mechanically, or both, with the bell and spigot metal surfaces or adjacent pipe metal surfaces; and
      iii) Seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements of Division 3.1 & 5.2 of this Plan.
2) Each cast iron caulked bell and spigot joint that is subject to pressures 25 psi or less and is exposed for any reason must be sealed by a means other than caulking.

Division 14.29: Protecting Cast-Iron Pipelines *(Reference 192.755)*

When an operator has knowledge that the support for a segment of a buried cast-iron pipeline is disturbed:

1) That segment of the pipeline must be protected, as necessary, against damage during the disturbance by:
   a) Vibrations from heavy construction equipment, trains, trucks, buses, or blasting;
   b) Impact forces by vehicles;
   c) Earth movement;
   d) Apparent future excavations near the pipeline; or
   e) Other foreseeable outside forces which may subject that segment of the pipeline to bending stress.
2) As soon as feasible, appropriate steps must be taken to provide permanent protection for the disturbed segment from damage that might result from external loads, including compliance with applicable requirements of Divisions 8.7, 8.8, and 9.10 of this Plan.

Division 14.30: Joining Plastic Pipe by Heat Fusion – Equipment Maintenance and Calibration *(Reference 192.756)*

Operator's must maintain equipment being used in the heat fusion joining of plastic pipe in accordance with the manufacturer's recommended practices or with written procedures that have been proven by test and experience to produce acceptable joints.

Additional Information:

1) Electrofusion equipment should be calibrated at the frequency stated by the manufacturer.
    a) Typically, electrofusion equipment must be sent to the manufacturer or equipment sales representative for calibration.
    b) Calibration records must be kept and retained for as long as the machine is being used.
2) For saddle, socket, and butt fusion equipment, the manufacturer's recommended maintenance schedule should be followed.
    a) The schedule and items to be inspected and maintained may vary by manufacturer and type of equipment.
    b) Maintenance records for saddle, socket, and butt fusion equipment must be kept and retained for as long as the equipment is being used.

CITY OF BLOOMFIELD, IOWA

DIVISION FIFTEEN

Qualification of Pipeline Personnel

49 CFR Part 192 Subpart N

Division 15.1: Qualification of Pipeline Personnel *(Reference Part 192 Subpart N)*

All of the requirements for 49 CFR Part 192 Subpart N may be found and are described in the IAMU Operator Qualification Plan Revision 1.0 (2/2019).

CITY OF BLOOMFIELD, IOWA

DIVISION SIXTEEN

Transmission Pipeline Integrity Management

49 CFR Part 192 Subpart O

Division 16.1: Scope *(Reference 192.901)*

This Division prescribes minimum requirements for an integrity management program on any gas transmission pipeline covered under this Plan. For gas transmission pipelines constructed of plastic, only the requirements of §192.917, 192.921, 192.935, and 192.937 apply.

Division 16.2: Division Definitions *(Reference 192.903)*

1) *Assessment* – The use of testing techniques as allowed in the Division to ascertain the condition of a covered pipeline segment.
2) *Confirmatory Direct Assessment* – Integrity assessment method using more focused application of the principle and techniques of direct assessment to identify internal and external corrosion in a covered transmission pipeline segment.
3) *Covered Segment or Covered Pipeline Segment* – A segment of gas transmission pipeline located in a high consequence area.
4) *Direct Assessment* – Integrity assessment method that utilizes a process to evaluate certain threats (*i.e.,* external corrosion, internal corrosion and stress corrosion cracking) to a covered pipeline segment's integrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.
5) *High Consequence Area* – An area established by one of the following methods:
   a) An area defined as –
      i) A Class 3 location
      ii) A Class 4 location
      iii) Any area in a Class 1 or 2 location where the potential impact radius is greater than 660 feet, and the area within a potential circle contains 20 or more buildings intended for human occupancy; or
      iv) Any area in a Class 1 or 2 location where the potential impact circle contains an identified site.
   b) The area within a potential impact circle containing –
      i) 20 or more buildings intended for human occupancy, unless the exception in paragraph d) applies; or
      ii) An identified site.
   c) Where a potential impact circle is calculated under either method a) or b) to establish a high consequence area, the length of the high consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy. (See figure E.I.A. in appendix E.)

(continued on next page)

d) If in identifying a high consequence area under paragraph a)(iii) of this definition or paragraph b)(i) of this definition, the radius of the potential impact circle is greater than 660 feet (200 meters), the operator may identify a high consequence area based on a prorated number of buildings intended for human occupancy with a distance of 660 feet (200 meters) from the centerline of the pipeline until December 17, 2006. If an operator chooses this approach, the operator must prorate the number of buildings intended for human occupancy based on the ratio of an area with a radius of 660 feet (200 meters) to the area of the potential impact circle (*i.e.*, the prorated number of buildings intended for human occupancy is equal to 20 × (660 feet) [or 200 meters]/potential impact radius in feet [or meters]^2).

6) *Identified Site* – Each of the following areas.
   a) An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or
   b) A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller-skating rinks; or
   c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.
7) *Potential Impact Radius (PIR)* - The radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula r = 0.69* (square root of (p*d^2)), where 'r' is the radius of a circular area in feet surrounding the point of failure, 'p' is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and 'd' is the nominal diameter of the pipeline in inches.
8) *Remediation* – A repair or mitigation activity an operator takes on a covered segment to limit or reduce the probability of an undesired event occurring or the expected consequences from the event.

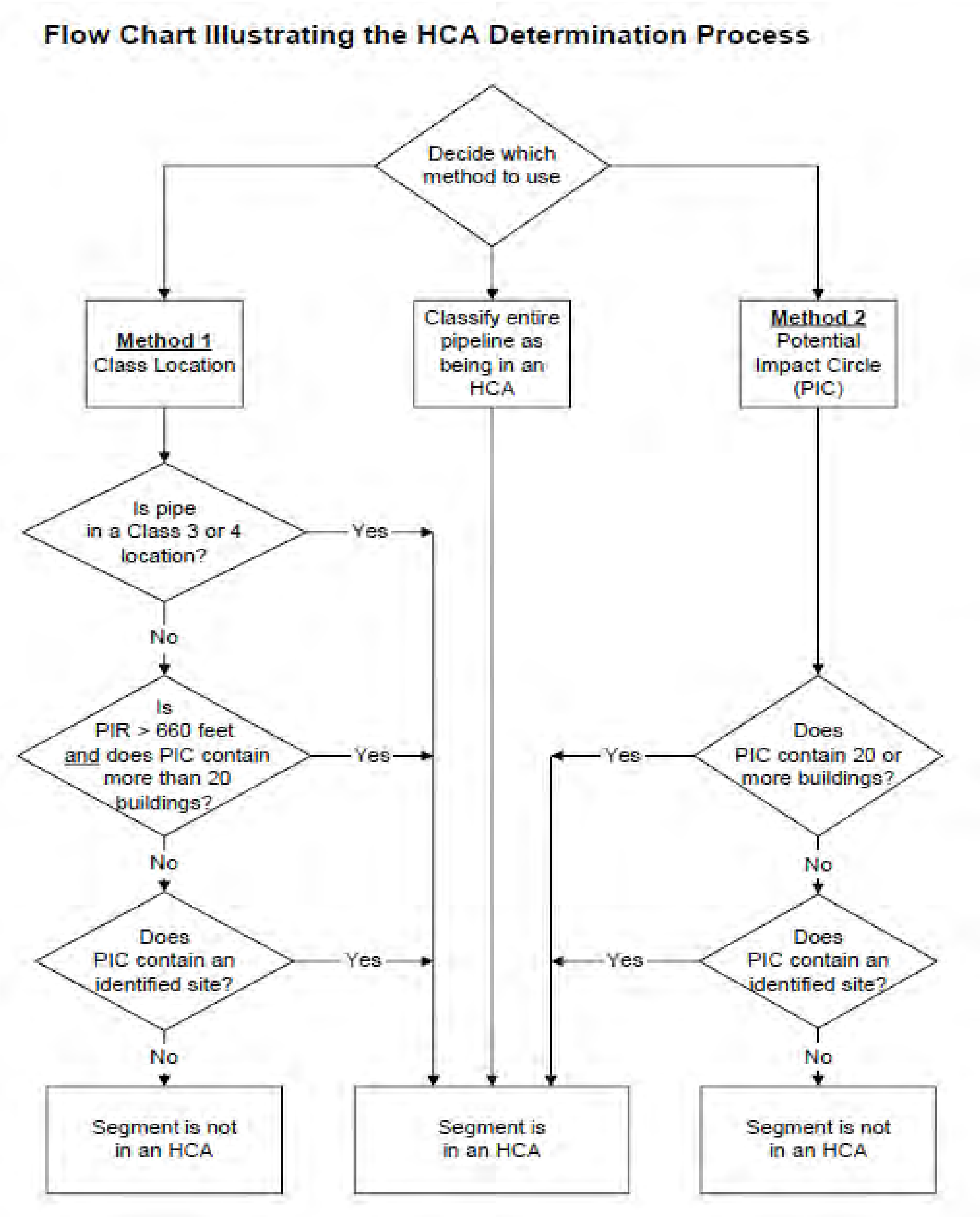
Division 16.3: Identifying a High Consequence Area *(Reference 192.905)*

1) *General:* An operator must use method a) or b) of part 5) of Division 16.2 of this Plan to identify a high consequence area. An operator may apply one method to its entire pipeline system, or apply one method to individual portions of the pipeline system. An operator must describe in its integrity management program which method it is applying to each portion of the operator's pipeline system. The description must include the potential impact radius when utilized to establish a high consequence area.
2) *Identified Sites:* An operator must identify an identified site, for purposes of this Division, from information the operator has obtained from routine operation and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate to the operator that they know of locations that meet the identified site criteria. These public officials could include officials on a local emergency planning commission or relevant Native American tribal officials.
   a) If a public official with safety or emergency response or planning responsibilities informs an operator that it does not have the information to identify an identified site, the operator must use one of the following sources, as appropriate, to identify these sites.
      i) Visible marking, or
      ii) The site is licensed or registered by a Federal, State, or local government agency; or
      iii) The site is on a list or map maintained by or available from a Federal, State, or local government agency and available to the general public.
3) *Newly-identified Areas*: When an operator has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions in Division 16.2 of this Plan, the operator must complete the evaluation using method a) or b) of part 5) of Division 16.2 of this Plan. If the segment is determined to meet the definition as a high consequence area, it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified.

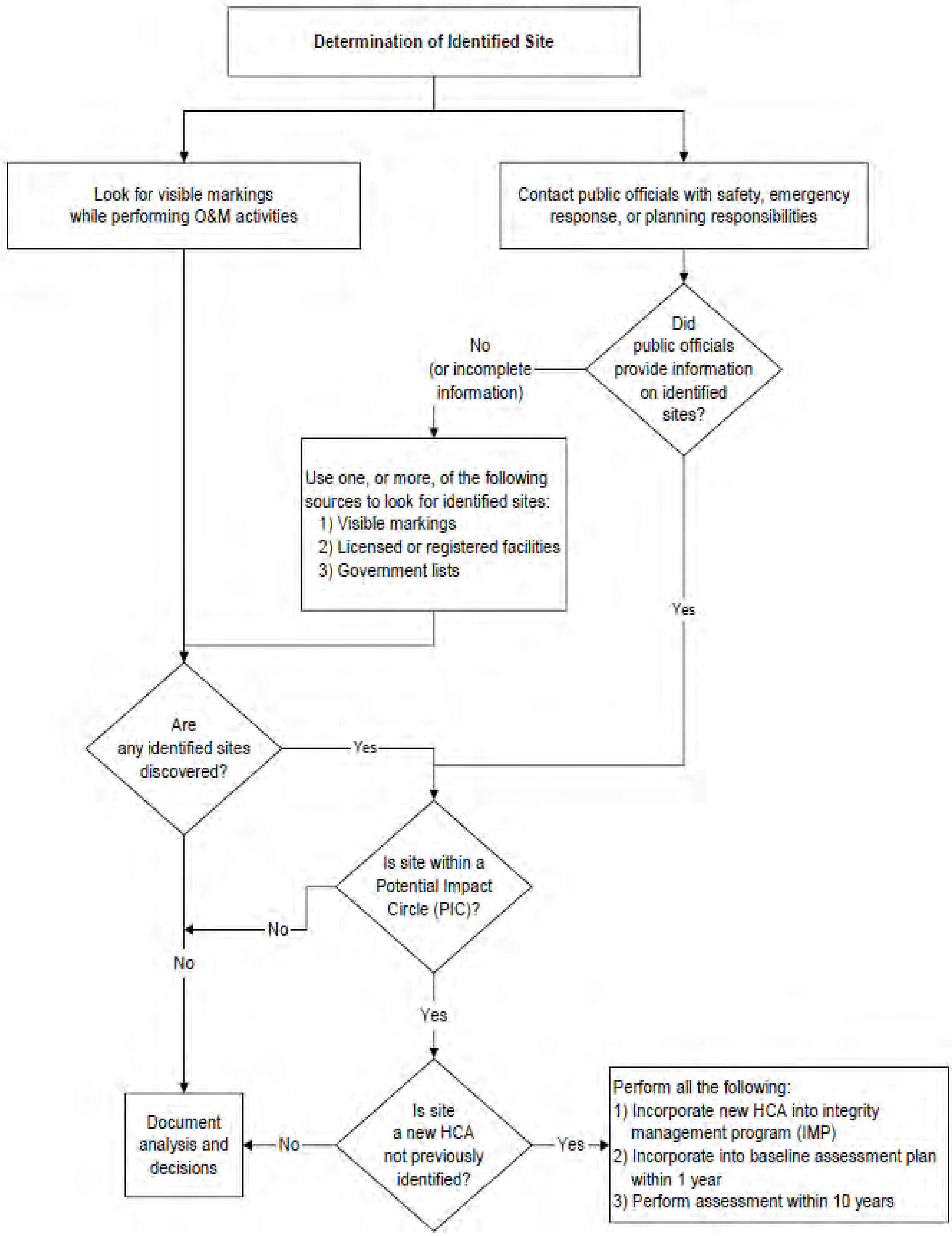
Additional Information:

1) A flow chart for determining if a transmission pipeline has a high consequence area has been provided on the following page.
2) A flow chart for determining if a transmission pipeline has an identified site has been provided on the following page.
3) Anytime conditions change along the transmission pipeline route, the operator should reassess the pipeline segment and determine if there has been a change in class location, an identified site, or high consequence area is now present.

(continued on next page)



Flow Chart for Determination of Identified Sites



Division 16.4: Implementing an Integrity Management Program *(Reference 192.907)*

1) General: No later than December 17, 2004, an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in §192.11 and that addresses the risks on each covered transmission pipeline segment. The initial integrity management program must consist, at a minimum, of a framework that describes the process for implementing each program element, how relevant decisions will be made and by whom, a time line for completing the work to implement the program element, and how information gained from experience will be continuously incorporated into the program. The framework will evolve into a more detailed and comprehensive program. An operator must make continual improvements to the program.
2) Implementation Standards: When carrying out the requirements of this Division, an operator must follow the requirements of this Division and ASME/ANSI B31.8S and its appendices, where specified. An operator may follow an equivalent standard or practice only when the operator demonstrates the alternative standard or practice provides and equivalent level of safety to the public and property.

Additional Information:

1) An operator must follow the requirements of Divisions 16.1 through 16.4 to determine if a high consequence area exists on transmission pipelines.
   a) If it is determined that a high consequence area does NOT exist on a transmission pipeline a written transmission integrity management plan (TIMP) is NOT required.
   b) If it is determined that a high consequence area DOES exist on a transmission pipeline, an operator must develop a written transmission integrity management plan (TIMP) that meets the additional requirements of 49 CFR Part 192 Subpart O (§192.909 - §192.951) that are not contained in this Plan.

CITY OF BLOOMFIELD, IOWA

DIVISION SEVENTEEN

Distribution Pipeline Integrity Management

49 CFR Part 192 Subpart P

Additional Information: To aid in meeting the requirements of distribution integrity management, it is recommended that an operator using this Plan, utilizes the APGA Security and Integrity Foundation SHRIMP Tool for developing and maintaining a written distribution integrity management plan (DIMP).

Division 17.1: Division Definitions *(Reference 192.1001)*

The following definitions apply specifically to this Division of this Plan.

Excavation Damage: Any impact that results in the need to repair or replace an underground facility due to a weakening, or the partial or complete destruction, of the facility, including, but not limited to, the protective coating, lateral support, cathodic protection or the housing for the line device or facility.

Hazardous Leak: A leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous.

Integrity Management Plan (IM Plan): A written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with 49 CFR Part 192 Subpart P.

Integrity Management Program (IM Program): An overall approach by an operator to ensure the integrity of its gas distribution system.

Mechanical Fitting: A mechanical device used to connect sections of pipe. The term "mechanical fitting" applies only to:

1) Stab type fittings;
2) Nut follower type fittings;
3) Bolted type fittings; or
4) Other compression type fittings

Division 17.2: What Type of Facilities are Included in an Integrity Management Plan *(Reference 192.1003)*

1) *General:* This Division prescribes the minimum requirements for an integrity management (IM) program for any gas distribution pipeline covered in this Plan, including liquified petroleum gas systems. A gas distribution operator must follow the requirements of this Division unless the following exemptions apply.
2) *Exceptions:* This Division DOES NOT apply to the following:
   a) Individual service lines directly connected to a production line or a gathering line other than a regulated onshore gathering line as determined in §192.8;
   b) Individual service lines directly connected to either a transmission or regulated gathering pipeline and maintained in accordance with §192.740(a) & (b); and
   c) Master meter systems.

Additional Information:

1) In order to comply with the requirements of Division 14.20, Pressure Regulating, Limiting and Overpressure Protection – Farm Taps (Service Lines Off of Transmission Pipelines) and operator may choose to add Farm Taps into their distribution integrity management plan (DIMP).
   a) It is recommended that if farm taps are added into DIMP, that language be incorporated into the DIMP specifically stating that farm taps have been identified and included into the plan.
2) If including farm tap service lines into DIMP so that inspection and testing is NOT required, consideration should be given to conducting inspection and testing of farm tap equipment as often as necessary to ensure it is functioning correctly.

<u>Procedures for the replacement or remediation of pipeline facilities that are known to leak based on material, design, or past operating and maintenance history:</u>

1) All leak and repair data is being entered into the Threat Assessment section of the Distribution Integrity Management Plan so that it may be analyzed and given a risk evaluation and prioritization. If a potential threat, based on risk ranking, is identified through analysis of leak and repair data, additional or accelerated measures are developed to mitigate the risk.
2) If at any time, through means of a PHMSA Advisory Bulletin or a manufacturer's written statement, an operator is notified that known materials contained within the system have been determined to fail or leak, those specific materials will be entered into the Distribution Integrity Management Plan (DIMP) for continual monitoring, threat assessment, risk evaluation and risk prioritization.

Division 17.3: Initial DIMP Implementation *(Reference 192.1005)*

A gas distribution operator must develop and implement a written distribution integrity management plan no later than August 2, 2011.

Additional Information:

1) If a gas distribution system is purchased or absorbed, the operator must develop and implement a written distribution integrity management plan within 6 months of the date that the gas distribution system was either purchased or absorbed and modified as additional information is obtained.

Division 17.4: Required Elements of an Integrity Management Plan *(Reference 192.1007)*

A written integrity management plan must contain procedures for developing and implementing the following elements:

1) *Knowledge:* An operator must demonstrate an understanding of its gas distribution system developed from reasonably available information.
   a) Identify the characteristics of the pipeline's design and operations and the environmental factors that are necessary to assess the applicable threats and risks to its gas distribution pipeline.
   b) Consider the information gained from past design, operations, and maintenance.
   c) Identify additional information needed and provide a plan for gaining that information over time through normal activities conduced on the pipeline.
   d) Develop and implement a process by which the IM program will be reviewed periodically and refined and improved as needed.
   e) Provide for the capture and retention of data on any new pipeline installed. The data must include, at a minimum, the location where the new pipeline is installed and the material of which it is constructed.
2) *Identify Threats:* The operator must consider the following categories of threats to each gas distribution pipeline:
   - Corrosion (including atmospheric corrosion)
   - Natural forces
   - Excavation damage
   - Other outside force damage
   - Material or welds
   - Equipment failure
   - Incorrect Operations
   - Other issues that could threaten the integrity of the pipeline.

(continued on next page)

   a) An operator must consider reasonably available information to identify existing and potential threats. Sources of data may include incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.

3) *Evaluate and Rank Risk:* An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure. An operator may subdivide its pipeline into regions with similar characteristics, and for which similar actions likely would be effective in reducing risk.
4) *Identify and Implement Measures to Address Risks:* Determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline. These measures must include an effective leak management program (unless all leaks are repaired when found).
5) *Measure Performance, Monitor Results, and Evaluate Effectiveness*
   a) Develop and monitor performance measures from an established baseline to evaluate the effectiveness of the DIMP. An operator must consider the results of its performance monitoring in periodically re-evaluating the threats and risks. These performance measures must include the following:
      i) Number of hazardous leaks either eliminated or repaired, categorized by cause;
      ii) Number of excavation damages;
      iii) Number of excavation tickets;
      iv) Total number of leaks either eliminated or repaired, categorized by cause;
      v) Number of hazardous leaks either eliminated or repaired, categorized by material; and
      vi) Any additional measures the operator determines are needed to evaluate the effectiveness of the DIMP in controlling each identified threat.
6) *Periodic Evaluation and Improvement:* An operator must re-evaluate threats and risks on its entire pipeline and consider the relevance of threats in one location to other areas. Each operator must determine the appropriate period for conducting complete program evaluations based on the complexity of its system and changes in factors affecting the risk of failure. An operator must conduct a complete program re-evaluation at least every 5 years. The operator must consider the results of the performance monitoring in these evaluations.
7) *Report Results:* Report, on an annual basis, the four measures listed in 5) a) i) through iv) of this section, as a part of the annual distribution report described in Division 1.6 of this Plan. An operator must also report the four measures to the state pipeline safety authority if a state exercises jurisdiction over the operator's pipeline.
   a) The four measures stated above that must be submitted to the state authority may be accomplished by submitting the annual distribution report to the Iowa Utilities Board through their EFS system.

Division 17.5: Record Requirements *(Reference 192.1011)*

An operator must maintain records demonstrating compliance with the requirements of this Division for at least 10 years. The records must include copies of superseded integrity management plans developed as required by this Division.

Division 17.6: Deviations from Required Periodic Inspections *(Reference 192.1013)*

1) An operator may propose to reduce the frequency of periodic inspections and tests required in this part on the basis of the engineering analysis and risk assessment required by this Division.
2) An operator must submit its proposal to the PHMSA Associate Administrator for Pipeline Safety or, in the case of an intrastate pipeline facility regulated by the State, the appropriate State agency (Iowa Utilities Board). The applicable oversight agency may accept the proposal on its own authority, with or without conditions and limitations, on a showing that the operator's proposal, which includes the adjusted interval, will provide an equal or greater overall level of safety.
3) An operator may implement an approved reduction in the frequency of a periodic inspection or test only where the operator has developed and implemented and integrity management program that provides an equal or improved overall level of safety despite the reduced frequency of periodic inspections.

Division 17.7: Requirements for Small LPG Operators *(Reference 192.1015)*

1) *General:* No later than August 2, 2011 a small LPG operator must develop and implement an IM program that includes a written IM plan as specified in paragraph 2) of this Division. The IM program for these pipelines should reflect the relative simplicity of these types of pipelines.
2) *Elements:* A written integrity management plan must address, at a minimum, the following elements:
   a) *Knowledge:* The operator must demonstrate knowledge of its pipeline, which, to the extent known, should include the approximate location and material of its pipeline. The operator must identify additional information needed and provide a plan for gaining knowledge over time through normal activities conducted on the pipeline.
   b) *Identify Threats:* The operator must consider, at minimum, the following categories of threats (existing and potential: Corrosion (including atmospheric corrosion), natural forces, excavation damage, other outside force damage, material or weld failure, equipment failure, and incorrect operations.
   c) *Rank Risks:* The operator must evaluate the risks to its pipeline and estimate the relative importance of each identified threat.
   d) *Identify and Implement Measures to Mitigate Risks:* The operator must determine and implement measures designed to reduce the risks from failure of its pipeline.
   e) *Measure Performance, Monitor Results, and Evaluate Effectiveness:* The operator must monitor, as a performance measure, the number leaks eliminated or repaired on its pipeline and their causes.
   f) *Periodic Evaluation and Improvement:* The operator must determine the appropriate period for conducting IM program evaluations based on the complexity of its pipeline and changes in factors affecting the risk of failure. An operator must re-evaluate its entire program at least every 5 years. The operator must consider the results of the performance monitoring in these evaluations.
3) *Records:* The operator must maintain, for a period of at least 10 years, the following records:
   a) A written IM plan in accordance with this Division, including superseding IM plans;
   b) Documents supporting threat identification; and
   c) Documents showing the location and material of all piping and appurtenances that are installed after the effective date of the operator's IM program and, to the extent known, the location and material of all pipe and appurtenances that were existing on the effective date of the operator's program.

CITY OF BLOOMFIELD, IOWA

DIVISION EIGHTEEN

Drug & Alcohol Testing

49 CFR Part 199

Division 18.1: Requirements for Drug & Alcohol Testing *(Reference 199.1 – 199.245)*

1) If an operator chooses to create and implement their own drug and alcohol testing policy, it must meet the requirements of 49 CFR Part 199.
2) If an operator chooses to join a consortium or use a third party for meeting the requirements of 49 CFR Part 199, it is ultimately the responsibility of the operator to ensure that the consortium or third party are following and meeting all of the requirements of 49 CFR Part 199.

Additional Information:

1) The operator must identify one person within the utility to be the Designated Employee Representative (DER) who will be responsible for receiving random testing requests, testing results, and overall implementation of the drug and alcohol policy.
2) Operators must ensure that management personnel responsible for determining that reasonable suspicion exists to require a covered employee to undergo drug and/or alcohol testing must receive training on the physical, behavioral, speech, and performance indicators of probable drug or alcohol misuse.
    a) Training must include 60 minutes on the signs and symptoms of drug misuse.
    b) Training must include 60 minutes on the signs and symptoms of alcohol misuse.
    c) A training certificate or proof of completion must be retained and available for inspection.
3) The following records must also be available upon request during inspection:
    a) Medical Review Officer (MRO) training and/or qualification records.
    b) Training and/or qualification records for personnel who administer urine collections.
    c) Calibration certificate for breath analysis machines used for alcohol testing.