API Recommended Practice 80 for Rural Gas Gathering Lines
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Introduction

This recommended practice contains provisions for the design, construction, testing, corrosion control, operation, and maintenance of onshore gas gathering lines in rural areas. The provisions are intended to compliment the U.S. Department of Transportation’s (DOT) requirements for regulated onshore gas gathering lines in 49 C.F.R. Part 192. DOT established those requirements in a March 2006 final rule and initiated an effort several years ago to regulate certain historically-exempt gas gathering lines in rural areas. This recommended practice aligns with that rulemaking effort and is limited to onshore gas gathering lines in rural areas that are not presently regulated by DOT.

This recommended practice is intended to address recent developments in the oil and gas industry, particularly the emergence of larger diameter, higher pressure gas gathering lines in shale plays. Most gas gathering lines in the United States do not share these operating characteristics, and the risk-based provisions in this recommended practice are not necessarily appropriate for the smaller diameter, lower pressure gas gathering lines that still predominate throughout industry.

The provisions in this recommended practice are intended to work together and should not be considered in isolation. For example, this recommended practice contains new definitions for production operation and onshore gas gathering line that may change the classification of certain pipelines. The subsequent provisions for the design, construction, testing, operation, and maintenance of rural gas gathering lines account for that change in status and would not necessarily be appropriate under different definitions.

Background

A brief overview of the efforts that led to the development of this recommended practice is necessary to fully understand its intent. In August 2011, DOT published an advance notice of proposed rulemaking (ANPRM) asking for public comment on the need to change the federal pipeline safety standards for gas gathering lines in 49 C.F.R. Part 192. (Docket No. PHMSA-2011-0023; 76 Fed. Reg. 53,086). Adopted in a March 2006 final rule, DOT’s regulations require operators to use the provisions in API Recommended Practice 80, “Guidelines for the Definition of Onshore Gas Gathering Lines,” 1st edition, April 2000, (RP 80), to determine if a pipeline is an onshore gas gathering line, subject to certain additional regulatory limitations in Part 192. If a pipeline is an onshore gas gathering line, DOT’s regulations require operators to determine if the pipeline meets the definition of a “regulated onshore gas gathering line”. Under the March 2006 final rule, regulated onshore gas gathering lines are limited to pipelines in more populated, Class 2, 3, or 4 locations. Onshore gas gathering lines in less populated, Class 1 locations are exempt from regulation.

After reviewing the public comments submitted in response to the ANPRM, DOT issued a notice of proposed rulemaking (NPRM) in April 2016 that contained substantial changes to the regulations for onshore gas gathering lines (Docket No. PHMSA-2011-0023; 81 Fed. Reg. 20,721). The NPRM sought to remove the reference to RP 80 in Part 192 and create a new definition of onshore gas gathering line. The NPRM also sought to establish new safety standards for onshore gas gathering lines in Class 1 locations that have a nominal outside diameter of 8 inches or greater and a maximum allowable operating pressure (MAOP) that produces a hoop stress of 20 percent or more of specified minimum yield strength (SMYS) for metallic lines or an MAOP of more than 125 pounds per square inch gauge (psig) for non-metallic lines. The American Petroleum Institute (API) and other industry representatives submitted comments opposing DOT’s proposed changes. API also expressed a willingness to consider revising RP 80 to address some of the concerns that DOT identified in the NPRM.
In 2017, API formed a working group of member companies and other industry representatives to consider potential revisions to RP 80. The working group agreed that potential changes to RP 80 should be considered, but only as part of a broader effort to create a new recommended practice for onshore gas gathering line safety. The working group felt that making isolated changes to RP 80 could have significant adverse impacts on the industry, particularly if DOT used those changes to justify the proposals contained in the NPRM. The working group believed that any changes to RP 80 should be directly tied to a new set of recommend practices for onshore gas gathering line safety. Otherwise, the working group reasoned, producers and operators of small diameter, low pressure conventional gas gathering systems could become subject to DOT’s transportation-related pipeline safety standards, including the regulations for gas transmission lines. On the other hand, the working group agreed that appropriate, risk-based safety practices should be established for the new generation of larger diameter, higher pressure gas gathering lines in Class 1 locations. The working group also agreed that certain safety measures, like participating in a qualified state one-call damage prevention program, should probably apply more broadly to all gas gathering line operators.

In January 2018, API convened an initial meeting in Houston, Texas, to discuss the development of a new recommended practice for onshore gas gathering lines. Nearly 100 people participated in the meeting, including representatives from pipeline companies, industry trade organizations, advocacy groups, and regulatory bodies. At the request of the Chair, the participants formed into four workgroups to address the following subjects: (1) risk categorization, (2) design, construction, and testing, (3) corrosion control, and (4) operations and maintenance. The Chair also formed another workgroup to address changes to RP 80. During the initial meeting, the participants agreed that the new recommended practice should only apply to rural gas gathering lines not regulated by DOT. The participants also agreed that two new risk categories should be included in the recommended practice: (1) a Type C designation for higher risk lines and (2) a Type D designation for lower risk lines. Finally, the workgroups agreed to convene on a regular basis to begin developing recommended safety practices for each of the other subject matter areas.

In March 2018, API convened another meeting in Houston, Texas, to discuss the recommended practice. At the beginning of the meeting, the workgroups updated the participants on their progress and shared certain proposals for comment. The risk categories workgroup proposed two methodologies for determining whether a pipeline should be classified as a Type C or Type D gathering line. The first method was a modified version of the process that is used to determine the class location of a pipeline under Part 192. The second method was a modified version of the potential impact radius or potential impact circle approach that is used to determine whether a gas transmission line is in a high consequence area under the Part 192 integrity management regulations.

In May 2018, API convened another meeting in Houston, Texas, to continue working on the recommended practice. At the start of the meeting, the workgroups reviewed the comments received on an initial draft version of the recommended practice and provided recommendations for potential resolution. After the individual workgroup sessions, the Chair held a general session to discuss the definitions of production operation and onshore gas gathering line and other outstanding comments. Industry representatives recommended certain changes to these definitions during the general session and continued to emphasize the need to include practical approaches for addressing gas gathering line safety in this recommended practice.

Overview of Provisions

This recommended practice contains provisions for the risk categorization, design, construction, testing, operation, and maintenance of rural gas gathering lines. A rural area is defined as a Class 1 location or Class 2 location that contains an onshore gas gathering that does not meet the definition of a regulated
onshore gas gathering line under Part 192. The intent of this definition is to limit the scope of this recommended practice to onshore gas gathering lines that are not presently regulated by DOT. Nothing in this recommended practice affects an operator’s obligation to comply with the Part 192 requirements for regulated onshore gas gathering lines.

As a general principle, this recommended practice applies to all new pipelines, but only certain provisions apply to existing pipelines. A new pipeline is defined as a pipeline that is placed into service after the adoption of this recommended practice, or an existing pipeline that is replaced or relocated. An existing pipeline is defined as a pipeline placed into service on or before the adoption of this recommended practice. To avoid the significant hardship that would arise from applying such provisions retroactively, the recommend practices for design, construction, and testing only apply to new pipelines. The remaining provisions for risk categorization, operation, and maintenance apply to all pipelines, whether new or existing. DOT’s Part 192 regulations contain a similar non-retroactivity provision.

This recommended practice contains three other important limitations. First, the provisions do not apply to production operations, except for purposes of the definitions in Section 3. Production operations are not part of a transportation-related pipeline system and should not be subject to the same recommended safety practices as gas gathering lines. Second, the provisions do not apply to gas gathering lines that are 12 inches or less in nominal outside diameter, unless the operator decides that a particular provision or set of provisions should be followed. Smaller diameter gas gathering lines (referred to in this recommended practice as Tier I pipelines) generally do not present the same risk as the new generation of larger diameter, higher pressure gathering lines in shale plays. Other factors may also make the application of certain recommended practices to small-diameter gas gathering lines unnecessary or inappropriate. Third, this recommended practice does not apply to gas gathering processing plants between certain identified points. Such plants perform a processing function and are not part of a pipeline transportation network.

This recommended practice contains a revised definition for onshore gas gathering line to provide greater clarity and consistency. The key changes include establishing new endpoints for a production operation and modifying the endpoint of a gas gathering operation to account for certain overriding limitations recognized in DOT’s regulations. New supplemental definitions are also provided for other important terms, such as gas gathering processing plant, gas gathering treatment facility, gas gathering compressor station, incidental gas gathering line, and gas gathering return line. The furthermost downstream concept is retained in the new definitions to accommodate the wide variation of onshore gas production and gathering operations.

This recommended practice contains new provisions for determining the risk category of rural gas gathering lines. DOT currently recognizes two risk categories for regulated onshore gas gathering lines in Class 2, 3, and 4 locations: (1) Type A gathering lines and (2) Type B gathering lines. Type A gathering lines include metallic lines with an MAOP that produces a hoop stress of 20 percent or more of SMYS and non-metallic lines with an MAOP of more than 125 psig. Type B gathering lines include metallic lines with an MAOP that produces a hoop stress of less than 20 percent of SMYS and non-metallic lines with an MAOP of 125 psig or less.

This recommended practice establishes two additional risk categories for rural areas that are consistent with DOT’s current approach: (1) Type C gathering lines and (2) Type D gathering lines. Type C gathering lines include metallic and non-metallic lines that have one or more buildings intended for human occupancy or public sites located within a certain distance of the pipeline. Type C gathering lines also include larger diameter pipelines or pipelines with a potential impact radius that exceeds a specified distance. All other rural gathering lines are classified as Type D gathering lines, i.e., metallic and non-metallic lines in rural
areas that do not have any buildings intended for human occupancy or public sites within a certain distance of the pipeline.

This recommended practice allows operators to use two methods to determine the risk category for a pipeline. The first method, the modified class location approach, requires operators to determine if a building intended for human occupancy or public site is located within a continuous 1-mile corridor along the centerline. For Tier II pipelines that are more than 12 inches and 24 inches or less in nominal outside diameter, the width of the corridor is the standard class location unit distance of 220 yards in either direction from the centerline. If a building intended for human occupancy or public site is located within the modified class location corridor, a Tier II pipeline is designated as a Type C gathering line. If not, a Tier II pipeline is designated as a Type D gathering line. To account for the potential impact to areas outside of the class location corridor in the unlikely event of an incident, Tier III pipelines that have a nominal outside diameter of more than 24 inches receive the Type C designation by default. This recommended practice notes that the width of the modified class location corridor for a Tier I pipeline is 110 yards in either direction from the centerline.

The second method for determining a pipeline’s risk category, the potential impact radius approach, requires operators to determine if a building intended for human occupancy or public site is located within a potential impact circle that slides continuously along the centerline. The radius of that potential impact circle is determined by the pipeline’s pressure, nominal outside diameter, and a factor representing the composition of the gas transported. The pressure used in the calculation is either the highest operating pressure experienced during a 1-year period, or the lowest overpressure protection setting for the pipeline. To avoid imposing unnecessary burdens on Type D gathering line operators, MAOP is not used in calculating the potential impact radius under this recommended practice. To reflect the greater likelihood of having liquid hydrocarbons present in the gas stream, the more conservative rich natural gas factor is used in the calculation, although the operator can use the lean gas factor where justified. If a building intended for human occupancy or public site is located within the potential impact circle, the pipeline is designated as a Type C gathering line. Otherwise, the pipeline is designated as a Type D gathering line. To account for the potential impact to areas outside of the standard class location corridor in the unlikely event of an incident, pipelines that have a potential impact radius of more than 220 yards receive the Type C designation by default. An operator can apply these provisions to a Tier I pipeline without modification.

This recommended practice contains design, construction, testing, corrosion control, operation, and maintenance provisions for Type C gathering lines. Consistent with the anti-retroactivity provision in Part 192, the recommended practices for design, construction, and testing only apply to new pipelines. Operators may use any material in a new pipeline that is qualified for use in gathering service, including steel, plastic, composite, and other non-metallics. The design, construction, and testing of new pipelines to substantiate MAOP should also be conducted in accordance with recognized and generally accepted industry practices. The recommended practices for corrosion control (e.g., external, internal, and atmospheric) and operation and maintenance (e.g., MAOP, damage prevention, public awareness, line markers, leak mitigation, and emergency response) apply to all Type C gathering lines, whether new or existing. This recommended practice also contains operations and maintenance provisions for Type D gathering lines, which are not likely to impact buildings intended for human occupancy or public sites and present a very low risk to public safety.

Broadly speaking, operators are instructed to follow recognized and generally accepted industry practices in implementing the provisions in this recommended practice. A recognized and generally accepted industry practice is defined as any code, standard, or recommended practice that provides an established method for performing a pipeline design, construction, testing, operation, or maintenance activity. This definition, which is based on a similar provision in the Occupational Health and Safety Administration’s
Process Safety Management Regulations, encourages innovation and provides operators with the ability to follow the latest established industry practices without requiring unnecessary revisions or updates to this recommended practice. Nothing in this recommended practice prohibits an operator from using an alternative method, standard, or practice that provides an equivalent or superior level of safety as demonstrated in appropriate supporting documentation.

Chart 1 – Gathering Line Class Determination
1 Scope

1.1 General

This recommended practice contains provisions for the risk categorization, design, construction, testing, corrosion control, operation, and maintenance of onshore gas gathering lines in rural areas.

1.2 New Pipelines

Except where otherwise noted, the provisions of this recommended practice apply to new pipelines.

1.3 Existing Pipelines

The design, construction, and testing provisions in Section 5 do not apply to existing pipelines. Except where otherwise noted, the risk categorization, corrosion control, and operation and maintenance provisions in Sections 4, 6, and 7 apply to existing pipelines.

Table 1 – Applicability Chart

<table>
<thead>
<tr>
<th>Risk Category (Section 4)</th>
<th>Design, Construction, Testing (Section 5)</th>
<th>Corrosion Control (Section 6)</th>
<th>Operations &amp; Maintenance (Section 7)</th>
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<td>New + Existing Pipelines</td>
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</tr>
<tr>
<td>Type D</td>
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1.4 Production Operations

Except for purposes of the definitions in Section 3, the provisions of this recommended practice do not apply to production operations.

1.5 Tier I Pipelines

Unless the operator determines otherwise, the provisions of this recommended practice do not apply to Tier I pipelines.

1.6 Gas Gathering Processing Plants

Except for bypass lines, the provisions in this recommended practice do not apply at gas gathering processing plants between the following two points:

- The inlet of the first pressure control device entering the plant, or another appropriate point within the plant boundaries as determined by the operator.
- The outlet of the last pressure control device exiting the plant, or another appropriate point within the plant boundaries as determined by the operator.

1.7 Conversion to Service

1.7.1 A pipeline previously used to transport a substance other than gas or in a production operation may be converted to a Type C gathering line if the operator implements a written procedure that meets the following conditions and is otherwise consistent with recognized and generally accepted industry practices:

- The design, construction, operation, and maintenance history of the pipeline is reviewed and, where sufficient historical records are not available, appropriate tests are performed to determine if the pipeline is in a satisfactory condition for safe operation.
- The pipeline is inspected for physical defects and operating conditions that could reasonably be expected to impair the integrity of the pipeline.
- All known unsafe defects and conditions are corrected.
- The pipeline is tested to substantiate the maximum allowable operating pressure in accordance with Section 5.7.
1.7.2 An operator should keep appropriate records of any investigations, tests, repairs, replacements, or alterations performed as part of a conversion to service for the useful life of the pipeline.

1.7.3 The conversion of service provisions in this section do not apply if a Type D gathering line becomes a Type C gathering line due to a change in population density or operating conditions.

1.8 Equivalency

1.8.1.1 Nothing in this recommended practice prohibits an operator from using an alternative method, standard, or practice that provides an equivalent or superior level of pipeline safety.

1.8.1.2 An operator should keep appropriate documentation to support a determination of equivalency or superiority under this section for the useful life of the pipeline.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the reference document (including any amendment) applies. [CONSIDER DELETING THIS SECTION AS UNNECESSARY. LIST OF RECOGNIZED AND GENERALLY ACCEPTED INDUSTRY PRACTICES TO BE PROVIDED IN ANNEX.]

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

For the purposes of this document, the following definitions apply.

3.1.1 anticipated operating conditions

The pressure, temperature, and other environmental conditions that are likely to occur during normal pipeline operations.

3.1.2 building intended for human occupancy

A residential, commercial, or industrial building that is occupied by people on a regular or continuous basis, such as a house, apartment, store, office, or plant. A building used for production or gas gathering operations is not a building intended for human occupancy if the occupants receive appropriate training on emergency response and evacuation procedures.

3.1.3 bypass line

A pipeline located on the grounds of a gas gathering processing plant that does not ordinarily deliver gas to one or more of the processing facilities.

3.1.4 central production facility

A facility at one or more locations downstream from a production site where gas produced at a well undergoes separation or treatment in preparation for delivery to a gathering line.

NOTE: For purposes of this definition, separation is the process used to segregate produced well fluids (oil, water, gas) with separator vessels, heater treaters, emulsion treaters, free water knockouts, chemelectric units, or other similar equipment. Treatment is the process used to enhance separation of produced well fluids and removal of impurities with iron sponge units, field amine units, dehydrators, or other similar equipment.

3.1.5 class location unit

An onshore area that extends 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline.

3.1.6 class 1 location...
A class location unit that has 10 or fewer buildings intended for human occupancy.

3.1.7 class 2 location
Any class location unit that has more than 10 but fewer than 46 buildings intended for human occupancy.

3.1.8 component
Any part of a pipeline other than pipe that is subject to system pressure.

3.1.9 existing pipeline
A pipeline placed into service on or before the adoption of this recommended practice.

3.1.10 gas gathering compressor station
A station where one or more compressors are used to lower upstream gathering line operating pressure to facilitate deliveries into the pipeline from production operations or to increase downstream gathering line pressure for delivery to a transmission line, distribution line, or storage facility.

3.1.11 gas gathering processing plant
A plant downstream from a production site or central production facility that is used to extract natural gas liquids and remove impurities from gas produced at a well in preparation for delivery to a transmission line, distribution line, or storage facility.

3.1.12 gas gathering return line
A pipeline used to transport gas from a gas gathering operation, transmission line, distribution line, or storage facility exclusively to points in or adjacent to one or more gas gathering operations for use as fuel gas, gas lift, or gas injection.

3.1.13 gas gathering treatment facility
A facility downstream from a production site or central production facility that is used to remove impurities from the gas stream to meet the downstream product specifications of a transmission or distribution line.

3.1.14 impracticable
An activity that cannot be accomplished without incurring unnecessary hardship or employing unreasonable measures.

3.1.15 impurities
Water, solids, and other non-hydrocarbon gases, such as carbon dioxide, hydrogen sulfide, nitrogen, oxygen, and helium.

3.1.16 incidental gas gathering line
A pipeline used to transport gas from the furthermost downstream point in a production operation (as defined in Section 3.1.25) or gas gathering operation (as defined in Section 3.1.20) directly to a transmission line, distribution line, or storage facility.

3.1.17 maximum allowable operating pressure (MAOP)
The maximum pressure allowed during normal pipeline operations.

3.1.18 natural gas liquids
Ethane, propane, butane, pentane, and natural gasoline.

3.1.19
new pipeline
A pipeline that is placed into service, or an existing pipeline that is replaced or relocated, after adoption of this recommended practice.

3.1.20 onshore gas gathering line
A pipeline used to transport gas from the furthermost downstream point in a production operation to one of the following points in a gas gathering operation, whichever is the furthermost downstream:

— The inlet of the first downstream gas gathering processing plant, unless sound engineering principles demonstrate that gathering extends to a plant further downstream,
— The outlet of the last gas gathering treatment facility,
— The last point where gas produced in the same or separate production fields is commingled, provided the fields are not more than 50 miles apart, unless sound engineering principles demonstrate that a longer separation distance is justified in a particular case, or
— The outlet of the last gas gathering compressor station.

An onshore gas gathering line also includes an incidental gas gathering line and a gas gathering return line.

3.1.21 pipe
A tube manufactured with steel, plastic, composite, or other material that is used to transport gas and other produced well fluids.

3.1.22 pipeline
Line pipe and components.

3.1.23 potential impact circle
A circle of radius equal to the potential impact radius (PIR) as measured from the centerline.

3.1.24 potential impact radius (PIR)
The radius of a circle as measured from the centerline within which the potential failure of a pipeline could have significant impact on people or property.

3.1.25 production operation
Piping, equipment, and other facilities used in the process of extracting gas from the ground in preparation for initial transportation.

A production operation includes a pipeline used to transport gas produced at a well to one of the following points, whichever is furthermost downstream:

— The first point where the flow from two or more production sites commingles,
— The outlet of the last central production facility, or
— If there is no point of commingling or central production facility, the point where the flow from a production site enters an onshore gas gathering line, transmission line, distribution line, or storage facility.

A production operation also includes a production gas return line.

3.1.26 production gas return line
A pipeline used to transport gas from a production operation exclusively to points in or adjacent to one or more production operations for use as fuel, gas lift, or gas injection.

3.1.27 production site
A well pad, leasehold, field, or other area within the operator’s control that is used to produce gas from a well.
3.1.28 **public site**
A building or 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 need not be consecutive).

3.1.29 **recognized and generally accepted industry practices**
Codes, standards, technical reports, or recommended practices that provide established methods for performing pipeline design, construction, testing, operation, or maintenance activities.

3.1.30 **rural area**
A Class 1 location or Class 2 location with an onshore gas gathering line that does not meet the definition of a regulated onshore gas gathering line under 49 C.F.R. §§ 192.8 to 192.9.

3.1.31 **Tier I**
A pipeline having a nominal outside diameter of 12 inches or less.

3.1.32 **Tier II**
A pipeline having a nominal outside diameter of more than 12 inches and less than or equal to 24 inches.

3.1.33 **Tier III**
A pipeline having a nominal outside diameter of more than 24 inches.

4 **Risk Categorization**

4.1 **General**
This section contains the provisions for determining the risk category of new and existing pipelines.

4.2 **Implementation**

4.2.1 **Initial Determination**
An operator should determine the initial risk category for all new pipelines before the pipeline is put into service. The risk category for all existing pipelines shall be determined every three years.

4.2.2 **Reevaluation**
An operator should reevaluate the risk category for a pipeline at least once every three years.

4.3 **Methods**
An operator shall use one, or both, of the methods provided in Sections 4.3.1 or 4.3.2 to determine the risk category for a pipeline.

4.3.1 **Modified Class Location**
The operator shall determine whether the pipeline is a Tier II pipeline or Tier III pipeline.

4.3.1.1 **Tier II Pipeline**
The operator of a Tier II pipeline shall determine whether the class location unit for a rural area contains either of the following:
- One or more buildings intended for human occupancy; or
- One or more public sites.

4.3.1.1.1 If the operator of a Tier II pipeline determines that the class location unit for a rural area satisfies either of the criteria described in Section 4.3.1.1, the pipeline shall be classified as a Type C gathering line, subject to the limitation provided in Section 4.3.1.1.3.
4.3.1.1.2 If the operator of a Tier II pipeline determines that the class location unit for a rural area does not satisfy either of the criteria described in Section 4.3.1.1, the pipeline shall be classified as a Type D gathering line.

4.3.1.1.3 The operator of a Tier II pipeline may limit the length of a Type C gathering line to a distance that extends 220 yards (200 meters) in either direction (as measured from the point where a perpendicular line drawn starting at the outermost edge of a building intended for human occupancy or public site crosses the centerline).

4.3.1.1.4 If the operator of a Tier I pipeline decides to follow the risk categorization provisions in Section 4.3.1, the length of the class location unit may be limited to an onshore area that extends 110 yards (100 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. The operator of a Tier I pipeline may also limit the length of a Type C gathering line to a distance that extends 110 yards (100 meters) in either direction (as measured from the point where a perpendicular line drawn starting at the outermost edge of a building intended for human occupancy or public site crosses the centerline).

4.3.1.2 Tier III Pipeline
The operator shall classify a Tier III pipeline as a Type C gathering line.

4.3.2 Potential Impact Radius
The operator shall calculate the potential impact radius for a pipeline using the following formula and values as appropriate.

4.3.2.1 Formula
The potential impact radius of a pipeline is determined by the formula \( r = 0.73 \times \sqrt{pd^2} \), where \( r \) is the radius of a circular area in feet surrounding the point of failure, ‘0.73’ is the factor for rich natural gas, ‘\( p \)’ is the operating pressure of the pipeline segment in pounds per square inch, and ‘\( d \)’ is the nominal diameter of the pipeline in inches.

4.3.2.2 Natural Gas Factor
4.3.2.2.1 The rich natural gas factor of 0.73 shall be used in the potential impact radius calculation, unless the operator determines that the use of the lean natural gas factor of 0.69 is justified.

4.3.2.2.2 To justify the use of the lean natural gas factor in a potential impact radius calculation, an operator shall demonstrate that the gross heating value of the gas composition is less than or equal to 1,100 Btu/cubic foot.

4.3.2.2.3 If an operator uses the lean natural gas factor in a potential impact radius calculation, appropriate documentation justifying that determination should be kept for the useful life of the pipeline.

4.3.2.3 Operating Pressure
4.3.2.3.1 Existing Pipelines
The operating pressure, or ‘\( p \)’, used in the potential impact radius calculation for an existing pipeline shall be either the highest actual operating pressure that the pipeline experienced in the previous 12 months, or the lowest overpressure protection setting for the pipeline.

4.3.2.3.2 New Pipelines
4.3.2.3.1.1 Initial Calculation
The operating pressure, or ‘\( p \)’, used in the initial potential impact radius calculation for a new pipeline shall be either the highest anticipated operating pressure that the pipeline is likely to experience in the first 12 months of operation, or the lowest overpressure protection setting for the pipeline, whichever is greater.
4.3.2.3.1.2 Subsequent Calculation

The operating pressure, or ‘p’, used in any subsequent potential impact radius calculation for a new pipeline shall be either the highest actual operating pressure that the pipeline experienced in the previous 12 months, or the lowest overpressure protection setting for the pipeline, whichever is greater.

4.3.2.4 Diameter

The operator shall determine the nominal diameter of the pipeline, or ‘d’, used in a potential impact radius calculation.

4.3.2.5 Potential Impact Circle

If the potential impact radius of a pipeline is 220 yards (200 meters) or less, the operator shall determine whether the potential impact circle contains either of the following:

— One or more buildings intended for human occupancy; or
— One or more public sites.

4.3.2.5.1 In making a determination under Section 4.3.2.5, the potential impact circle extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either a building intended for human occupancy or a public site to the outermost edge of the last contiguous potential impact circle that contains either a building intended for human occupancy or a public site.

4.3.2.5.2 If the operator determines that the potential impact circle satisfies either of the criteria described in Section 4.3.2.5, the pipeline shall be classified as a Type C gathering line.

4.3.2.5.3 If the operator determines that the potential impact circle does not satisfy either of the criteria described in Section 4.3.2.5, the pipeline shall be classified as a Type D gathering line.

4.3.2.6 Large Potential Impact Radius

An operator shall classify a pipeline as a Type C gathering line if the potential impact radius is greater than 220 yards (200 meters).

4.4 Centerline Data Inaccuracy

An operator shall take reasonable account of potential inaccuracies in centerline data in determining the risk category for a pipeline.

4.5 Information

An operator shall consider reasonably available sources of information in determining the risk category for a pipeline.

5 Design, Construction, and Testing

5.1 General

This section contains design, construction, and testing provisions for new pipelines.

5.2 Materials

5.2.1 Materials for pipe and components shall be:

— Capable of maintaining structural integrity under anticipated operating conditions,
— Compatible with any substances transported, and
— Qualified for use in accordance with recognized and generally accepted industry practices.

5.2.2 An operator should keep appropriate records documenting the materials for pipe and components for the useful life of the pipeline.

5.3 Design
5.3.1 Pipe and components shall be designed in accordance with recognized and generally accepted industry practices to withstand anticipated operating conditions, including internal pressures and external loads.

5.3.2 An operator should keep appropriate records documenting the design of pipe and components for the useful life of the pipeline.

5.4 Construction

5.4.1 A pipeline shall be constructed in accordance with recognized and generally accepted industry practices.

5.4.2 An operator should keep appropriate construction records for the useful life of the pipeline.

5.5 Cover

5.5.1 If a pipeline is buried at the time of installation, an operator should consider providing at least 30 inches of cover in normal soil and 18 inches of cover in consolidated rock, except where impracticable.

5.5.2 If a pipeline is buried at the time of installation, an operator should consider providing additional cover at rail, road, or water crossings.

5.5.3 If a pipeline is not buried at the time of installation, or a buried pipeline is provided with less cover than recommended in Section 5.5.1 for reasons of impracticability, an operator should consider implementing other measures to protect the pipeline from atmospheric corrosion and external forces.

5.6 Location

An operator should keep appropriate records documenting the location of pipe and components for the useful life of the pipeline.

5.7 Testing

5.7.1 A pipeline shall be tested in accordance with recognized and generally accepted industry practices to substantiate maximum allowable operating pressure.

5.7.2 Testing to substantiate maximum allowable operating pressure shall not be required if a component carries a pressure rating established in accordance with recognized and generally accepted industry practices.

5.7.3 Appropriate records documenting the medium, pressure, and duration of a test to substantiate maximum allowable operating pressure should be kept for the useful life of the pipeline.

6 Corrosion Control

This section contains corrosion control and cathodic protection provisions for Type C gathering lines.

6.1 Implementation

The operator of a new pipeline should implement the provisions of this section within 12 months of completing construction. The operator of an existing pipeline should implement the provisions of this section within 24 months of determining that the pipeline is a Type C gathering line, except where impracticable.

6.2 External Corrosion Control for Buried or Submerged Pipelines

6.2.1 Cathodic Protection

6.2.1.1 General

A buried metallic pipeline shall have a cathodic protection system that is consistent with recognized and generally accepted industry practices, unless the operator demonstrates any of the following by tests, investigations, or experience:

— A corrosive environment does not exist,
— The pipe material is suitable for its design life without cathodic protection, or
— The installation of a cathodic protection system is impractical.

6.2.1.2 Test Stations
If a pipeline is under cathodic protection, the operator shall have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection.

6.2.1.3 Unprotected Pipelines
An operator shall evaluate a buried pipeline that does not have a cathodic protection system at least once every 5 years and apply appropriate protective measures in areas where active corrosion is found.

6.2.1.4 Monitoring
A pipeline under cathodic protection shall be tested for adequate levels of cathodic protection at least once every 2 years.

6.2.1.4.1 A rectifier or other impressed current power source shall be inspected for proper operation at least once every 3 months.

6.2.1.4.2 A reverse current switch, diode, and interference bond whose failure would jeopardize structure protection shall be electrically checked for proper performance at least once every 3 months.

6.2.1.5 Remedial Action
An operator shall take remedial action to correct any deficiencies indicated by the monitoring performed in accordance with Section 6.2.1.4. The remedial actions shall be completed within a timeframe commensurate with the identified threat.

6.2.2 Coating
6.2.2.1 If cathodic protection is applied, a new metallic pipeline shall have an external protective coating.

6.2.2.1.1 If applied, an operator shall protect external protective coating from damage resulting from adverse ditch conditions or damage from supporting blocks.

6.2.3 Electrical Isolation
6.2.3.1.1 A buried or submerged metallic pipeline should be electrically isolated where necessary to facilitate the application of corrosion control.

6.2.3.1.2 A cathodically protected pipeline should be electrically isolated from metallic casings that are part of an underground system where corrosion is a threat, unless other measures are taken to minimize corrosion of the pipeline inside the casing.

6.2.3.1.3 Inspection and electrical tests should be made to ensure that electrical isolation is adequate. An isolation device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

6.2.3.1.4 Where a buried or submerged metallic pipeline is located in close proximity to electrical transmission tower footings, ground cables, or counterpoise, the pipeline should be protected against damage due to fault currents or lightning and protective measures should be taken at isolating devices.

6.2.4 Stray currents
If a pipeline is subjected to stray currents, the operator shall address the detrimental effects of such currents. An impressed current-type cathodic protection system or galvanic anode system shall be designed and installed to minimize any adverse effects on existing adjacent underground metallic structures.

6.3 Internal Corrosion Control
If a corrosive gas stream is transported in a buried metallic pipeline, the operator shall take steps to minimize corrosion or demonstrate that the level of corrosivity is acceptable given the design life of the pipeline. An operator should conduct monitoring to determine the effectiveness of the steps taken.

6.4 Atmospheric Corrosion Control

An operator should inspect, as appropriate, a pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion. If atmospheric corrosion is found that could affect the safe operation of the pipeline, the operator shall take appropriate remedial action.

6.5 Determining the Remaining Strength of Pipe

An operator may determine the strength of pipe based on actual remaining wall thickness in accordance with recognized and generally accepted industry practices.

6.6 Corrosion Control Records

An operator should keep records documenting the adequacy of corrosion control measures for at least five years.

7 Operations and Maintenance

7.1 General

This section contains operations and maintenance requirements for new and existing pipelines.

7.1.1 The operations and maintenance provisions in Section 7.3 apply to Type C gathering lines. The operations and maintenance provisions in Section 7.4 apply to Type D gathering lines.

7.2 Implementation

7.2.1 Existing Pipelines

An operator of an existing pipeline should develop and implement a program to comply with the operations and maintenance provisions in this section within 12 months of determining the risk category for a pipeline.

7.2.2 New Pipelines

An operator of a new pipeline should develop and implement a program to comply with the operations and maintenance provisions of this section within 12 months of placing the pipeline into service.

7.3 Type C Gathering Lines

7.3.1 Maximum Allowable Operating Pressure

The operating pressure shall not exceed the maximum allowable operating pressure of the pipeline as determined in accordance with recognized and generally accepted industry practices.

7.3.1.1 For a new pipeline, the maximum allowable operating pressure shall not exceed the lowest of the following pressures, as applicable:

- The design pressure of the pipeline.
- The test pressure of the pipeline.
- The maximum safe pressure after considering the history of the pipeline, particularly known corrosion and the actual operating pressure.

7.3.1.2 For an existing pipeline, or a pipeline that changes from a Type D to a Type C gathering line after adoption of this recommended practice, the maximum allowable operating pressure shall not exceed the lowest of the following pressures, as applicable:

7.3.1.2.1 The highest actual operating pressure that the pipeline experienced in the five years prior to implementation of this recommended practice or the change in risk category, whichever is later, unless the pipeline is tested to substantiate the maximum allowable operating pressure or is uprated to increase the previously established maximum allowable operating pressure.
7.3.1.2.2 The maximum safe pressure after considering the history of the pipeline, particularly known corrosion and the actual operating pressure.

7.3.1.3 An operator should keep appropriate records documenting established maximum allowable operating pressure for the useful life of the pipeline.

7.3.2 Uprating

7.3.2.1 The previously established maximum allowable operating pressure of a pipeline may be increased if the operator implements a written procedure that meets the following conditions and is otherwise consistent with recognized and generally accepted industry practices.

7.3.2.1.1 The design, construction, testing, operation, and maintenance history of the pipeline is reviewed to determine if the higher maximum allowable operating pressure is safe.

7.3.2.1.2 The pipeline is inspected for physical defects and operating conditions that could reasonably be expected to impair the integrity of the pipeline.

7.3.2.1.3 Any physical defects and operating conditions discovered during an inspection are repaired or corrected.

7.3.2.1.4 Records are available to demonstrate that the pipeline previously received an adequate test to a pressure greater than or equal to the higher maximum allowable operating pressure.

7.3.2.1.5 If records are not available to demonstrate that the pipeline previously received an adequate test, the pressure of the pipeline is increased in appropriate increments to substantiate the higher maximum allowable operating pressure, provided that appropriate action is taken after each incremental increase to detect and remediate leaks.

7.3.2.1.6 The higher maximum allowable operating pressure does not exceed the maximum allowable operating pressure permitted for a new line of the same design in the same location.

7.3.2.2 Appropriate records of any investigations, tests, repairs, replacements, and alterations performed in uprating the previously established maximum allowable operating pressure of a pipeline should be kept for the useful life of the pipeline.

7.3.3 Damage Prevention Program

An operator shall participate in an applicable state one-call or call-before-you-dig damage prevention program.

7.3.4 Public Awareness

An operator should develop and implement a public awareness program to educate the public, emergency responders, and persons engaged in excavation-related activities on the essential elements identified in Section 7.3.4.1.

7.3.4.1 Essential Elements

A public awareness program shall include provisions that address the following topics.

— Use of a one-call notification system prior to excavation;

— Possible hazards associated with unintended releases of gas from a pipeline;

— Physical indications that a release of a gas from a pipeline may have occurred;

— Steps that can be taken to protect the public if gas is released from a pipeline; and

— Procedures for reporting an unintentional release of gas from a pipeline.

7.3.4.2 Additional Elements

A public awareness program may include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations.

7.3.4.3 Local Knowledge
An operator may use local knowledge to identify the affected stakeholders covered in a public awareness program.

7.3.4.4 Operator Discretion
An operator may exercise discretion in determining the appropriate means of educating affected stakeholders, given local conditions.

7.3.5 Line Markers
7.3.5.1 Location
Buried pipelines shall have a line marker placed at the crossing of a public roadway, an active railway, or any other location deemed appropriate by the operator.

7.3.5.2 Warning
A new or replaced line marker shall include a warning notifying the public about the presence of a gas pipeline and the operator contact information.

7.3.5.3 Inspection
An operator shall inspect line markers where practicable during the performance of other field activities. If the inspection indicates that a line marker is missing or contains inaccurate information, appropriate remedial action should be taken.

7.3.5.4 Aboveground Installations
Markers or other signs may be placed at above-ground piping or facilities.

7.3.6 Leaks
7.3.6.1 Leak Evaluation
A leak evaluation should be conducted at least once every three calendar years, not to exceed 39 months, or more frequently if deemed necessary by the operator based on local knowledge or leak history.

7.3.6.2 Leak Mitigation
An operator shall mitigate a leak that presents an immediate hazard to the public.

7.3.7 Emergency Response
An operator should have a means for receiving and responding to notifications concerning a pipeline emergency.

7.4 Type D Gathering Lines
7.4.1 One Call Program
An operator should participate in an applicable state one-call or call-before-you-dig damage prevention program.

7.4.2 Line Markers
7.4.2.1 Location
Buried pipelines should have a line marker placed at the crossing of a public roadway, an active railway, or any other location deemed appropriate by the operator.

7.4.2.2 Warning
A new or replaced line marker should include a warning notifying the public about the presence of a gas pipeline and the operator contact information.

7.4.2.3 Inspection
An operator should inspect line markers where practicable during the performance of other field activities. If the inspection indicates that a line marker is missing or contains inaccurate information, appropriate remedial action should be taken.

7.4.2.4 Aboveground Installations
Markers or other signs may be placed at above-ground piping or facilities.

7.4.2.5 Leak Mitigation
An operator shall mitigate a leak that presents an immediate hazard to the public.

7.4.2.6 Emergency Response
An operator should have a means for receiving and responding to notifications concerning a pipeline emergency.
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- Publisher: Gas Technology Institute (GTI), 1700 South Mount Prospect Road, Des Plaines, IL 60018 (www.gastechnology.org)

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- NACE SP0169-2013, Control of External Corrosion on Underground or Submerged Metallic Piping Systems
- NACE SP0177-2014, Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems
- Publisher: National Association of Corrosion Engineers (NACE International), 1440 South Creek Drive, Houston, TX 77084-4906 (www.nace.org)

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- Publisher: National Fire Protection Association (NFPA) 1 Batterymarch Park, Quincy, MA 02169-7471 (www.nfpa.org)

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Production Scenarios

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<th>Transmission or Distribution</th>
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<td>Gathering</td>
<td>Production Site</td>
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<tr>
<td>Well</td>
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**Scenario #1: Point of Commingling**

**Scenario #2: Central Production Facility**
Scenario #3: No Point of Commingling & No Central Production Facility
Gathering Scenarios

<table>
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Production Site

Well

Gathering Process Flow:
- Production Site
- Incidental Gathering Line
- Gas Gathering Compressor Station
- Gas Gathering Compressor Station
- Gas Gathering Processing Plant
- Gas Gathering Return Line
- Central Production Facility
- Incidental Gathering Line
- Gas Gathering Compressor Station
- Gas Gathering Processing Plant
- Gas Gathering Return Line