Description	To establish the process for determining the Maximum Allowable Operating Pressure (MAOP) for gas pipeline facilities.	
Regulatory Applicability	☒ Regulated Transmission Pipelines ☒ Regulated Gathering Pipelines (Type A) ☒ Regulated Gathering Pipelines (Type B) ☒ Distribution Pipelines	
Frequency	As needed	
Reference	49 CFR 192.619	*Maximum Allowable Operating Pressure: Steel or Plastic Pipelines*
	49 CFR 192.620	*Alternative maximum allowable operating pressure for certain steel pipelines*
	49 CFR 192.621	*Maximum allowable operating pressure: High-pressure distribution systems*
	49 CFR 192.623	*Maximum and minimum allowable operating pressure; Low-pressure distribution systems*
	49 CFR 192.624	*Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines.*
	49 CFR 192.632	*Engineering Critical Assessment Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines*.
Forms / Record Retention	F-192.619	*MAOP Determination / Life of Pipeline System*
Related Specifications	ASME/ANSI B31.8-2003	*Gas Transmission and Distribution Piping Systems*
OQ Covered Task	None	

Procedure Steps

Transmission and Gathering

1. Gather the following information to complete form F-192.619 and calculate the maximum allowable operating pressure of the pipeline that commensurate with the class location.
   a) Class location
   b) Pipe specification – yield strength, nominal wall thickness, outside diameter
   c) Gas temperature in pipeline
   d) Type of longitudinal seams
   e) Date of pipe manufacture
   f) Flange pressure rating
   g) Component pressure ratings
   h) Pipeline pressure test
2. Use this data to determine which is lower:
   a) The design pressure of the weakest element;
   b) Test pressure divided by the applicable following factors:

Class location	Factors			
	Installed prior to 11-12-70	Installed after 11-11-70	Installed on or after 7-1-2020	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

For a component whose design pressure is not known, pressure test factor is ≥ 1.3

   c) Highest actual operating pressure to which the pipeline was subjected during the 5 years preceding the applicable date in the second column of the table below. This pressure restriction applies unless the segment was tested according to the requirements of 49 CFR Subpart J after the applicable date in the third column or the segment was uprated according to the requirements in 49 CFR Subpart K.

Pipeline Segment	Pressure Date	Test Date
Onshore gathering line that first became subject to 49 CFR 192 (other than 612) after 4-13-06	March 15, 2006, or date line becomes subject to 49 CFR 192, whichever is later	5 years preceding applicable date in second column
Onshore transmission line that was a gathering line not subject to 49 CFR 192 before 3-15-06	7-1-1976	7-1-1971
All other pipelines	7-1-1970	7-1-1965

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 §192.607, if applicable, and the history of the pipeline segment, including known corrosion and actual operating pressure

3. No segment of the pipeline may be operated at a pressure that exceeds the MAOP as determined in F-192.619.
4. Notwithstanding the requirements in paragraphs (a) through (d) of this section, operators of onshore steel transmission pipelines that meet the criteria specified in §192.624(a) must establish and document the maximum allowable operating pressure in accordance with §192.624.
5. Operators of onshore steel transmission pipelines must make and retain records necessary to establish and document the MAOP of each pipeline segment in accordance with paragraphs (1) through (5) of this section 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 §192.624, 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.

Note: The requirements of pressure restrictions described in this procedure do not apply if the pipeline is in satisfactory condition, considering its operations and maintenance history, and the highest actual operating pressure of the pipeline during 5 years preceding the applicable date in the second column of the above table. 49 CFR Part 192.611 must still be followed.

In the unlikely event WTG will need to utilize an Alternative Maximum Allowable Operating Pressure, a written process will be developed and all regulations within CFR 192.620 will be followed.

Distribution

1. High-Pressure Distribution

   For a segment of a high-pressure distribution system, the MAOP cannot exceed the lowest of the following, as applicable:

   a) The design pressure of the segment's weakest element

   b) 60 psig for a distribution system segment otherwise designated to operate at over 60 psig, unless the segment service lines are equipped with service regulators or other pressure limiting devices in series that meet 49 CFR Part 192.197(c) requirements

c) The pressure the operator determines to be the maximum safe pressure after considering the segment's history. In conformance with 49 CFR Part 192.195, overpressure protective devices must be installed in a manner that will prevent exceeding the MAOP.

2. Low-Pressure Distribution

For a low pressure distribution system, the MAOP cannot exceed a pressure high enough to make operating any connected and properly adjusted low pressure gas-burning equipment unsafe

A low-pressure distribution system may not be operated at a pressure lower than the minimum pressure at which safely and continuously operating any connected and properly adjusted low pressure gas burning equipment can be assured.

Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines.

1. Applicability.

West Texas Gas will review all MAOP documentation of onshore steel transmission pipeline segments to ensure records are traceable verifiable and complete (TVC). In situations where records are not TVC, WTG will follow this reconfirmation procedure. For the following segments;

i. A high consequence area as defined in §192.903; or

ii. A Class 3 or Class 4 location.

2. Currently WTG's pipeline segment's MAOP are established in accordance with §192.619(a. Thus, currently §192.619(c) is not applicable to WTG. The list of applicable segments for MAOP reconfirmation can be found on the compliance drive under reconfirmation file. Procedures and completion dates.

For applicable pipelines that MAOP reconfirmation is required one of the following 5 methods must be completed; Method 1 pressure test(including spike test and material verification) Method 2 pressure reduction Method 3 critical engineering assessment (ECA) Method 4 pipe replacement Method 5 pressure reduction for segments with small PIR. Details of the processes can be found below. The following schedule will be utilized. WTG must complete all actions required by this section on at least 50% of the pipeline mileage by July 3, 2028.

a) WTG must complete all actions required by this section 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 §192.624(a) (e.g., due to a location becoming a high consequence area), whichever is later.

b) If operational and environmental constraints limit an operator from meeting the deadlines in §192.624, the operator may petition for an extension of the completion deadlines by up to 1 year, upon submittal of a notification in accordance with §192.18. The notification must include an up-to-date plan for completing all actions in accordance with this section, 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.

a) One of the following 5 methods must be utilized to reconfirm MAOP for segments that do not have TVC documentation. Method 1: Pressure test. Perform a pressure and verify material properties records in accordance with §192.607 and the following requirements:

   i. Pressure test. Perform a pressure test in accordance with subpart J of §192.. 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). Which will include a spike pressure test for segments operating at a stress level greater =/ > 30% SMYS in accordance with §192.506.

   ii. 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 (minimum yield strength, ultimate tensile strength).

   iii. Material properties verification. If any of the records required by paragraph (c)(1)(ii) of this section are not documented in traceable, verifiable, and complete records, the operator must obtain the missing records in accordance with §192.607. 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 §192.607.

b) 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 (i.e., the location-specific operating pressure at each location).

   i. Where the pipeline segment has had a class location change in accordance with §192.611, and records documenting diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), 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 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.

ii. Future uprating of the pipeline segment in accordance with subpart K is allowed if the MAOP is established using Method 2.

iii. If WTG 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 §192.18 no later than 7 calendar days after establishing the reduced MAOP. 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 §192.624(c)(2);

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 section 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 §192.607, 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.

c) Method 3: Engineering Critical Assessment (ECA). Conduct an ECA in accordance with §192.632.

d) Method 4: Pipe Replacement. Replace the pipeline segment in accordance with this part.

e) 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:

i. 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 differences 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 (i.e., the location specific operating pressure at each location);

ii. 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 1 to §192.624(c)(5)(ii):

Table 1 to §192.624(c)(5)(ii)

Class locations	Patrols	Leakage surveys
(A) Class 1 and Class 2	3 1/2 months, but at least four times each calendar year	3 1/2 months, but at least four times each calendar year.
Class 3 and Class 4	3 months, but at least six times each calendar year	3 months, but at least six times each calendar year.

iii. Under Method 5, future uprating of the pipeline segment in accordance with subpart K is allowed.

f) Method 6: Alternative Technology. WTG 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 §192.18. The notification must include descriptions of the following details:

i. The technology or technologies to be used for 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;

ii. Procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects and flaws, and remediate defects discovered;

iii. Pipeline segment data, including original design, maintenance and operating history, anomaly or flaw characterization;

iv. 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 specified minimum yield strength;

v. 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 paragraph §192.712;

vi. Operational monitoring procedures;

vii. Methodology and criteria used to justify and establish the MAOP; and

viii. Documentation of the operator's process and procedures used to implement the use of the alternative technology, including any records generated through its use.

3. WTG must retain records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this section for the life of the pipeline.

Engineering Critical Assessment

When WTG conducts an MAOP reconfirmation in accordance with "Method 3" in the above paragraph, using an ECA to establish the material strength and MAOP of the pipeline segment, the ECA must comply with §192.632. The ECA must assess: Threats; loadings and 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.