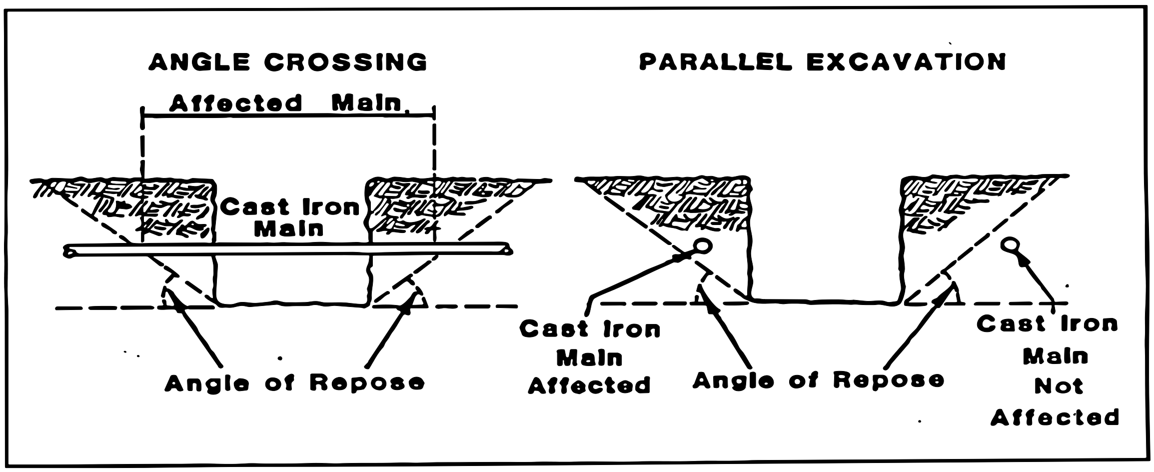
NOTE: If replacement is deemed necessary, replacement shall be made prior to the proposed third-party excavation activity, if feasible.

Where the replacement crosses an excavation, the replacement section should be centered so as to extend an approximately equal distance on each side of the excavation.

If the excavation is adequately protected by structural shoring (sheeting) against movement of the cast-iron main and the excavation fill is well tamped, the main does not need to be replaced.

10. Surveillance and/or Leakage Surveys

Surveillance and/or leakage surveys shall be considered on any portion of cast-iron piping during and after any excavation or other activity that would create stress on the piping. Particular attention shall be paid both during and after any excavation, to the possibility of leaking joints and



breaks.

During periods of extreme cold weather that causes soil freezing (frost) to cast-iron main depths, consideration shall be given to performing precautionary leakage surveys.

Cast-iron piping with a MAOP of 10 psig or more shall be leak surveyed annually.

....

§192.275 Cast iron pipe.

(a) Each caulked bell and spigot joint in cast iron pipe must be sealed with mechanical leak clamps.

(b) 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.

(c) Cast iron pipe may not be joined by threaded joints.

(d) Cast iron pipe may not be joined by brazing.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-62, 54 FR 5628, Feb. 6, 1989]

§ 192.317 Protection from hazards.

(a) The operator must take all practicable 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 to sustain abnormal loads. In addition, the operator must take all practicable steps to protect offshore pipelines from damage by mud slides, water currents, hurricanes, ship anchors, and fishing operations.

(b) Each aboveground transmission line or main, not located offshore or in inland navigable water areas, must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.

(c) Pipelines, including pipe risers, on each platform located offshore or in inland navigable waters must be protected from accidental damage by vessels.

[Amdt. 192–27, 41 FR 34606, Aug. 16, 1976, as amended by Amdt. 192–78, 61 FR 28784, June 6, 1996]

§ 192.361 Service lines: Installation.

(a) *Depth.* Each buried service line must be installed with at least 12 inches (305 millimeters) of cover in private property and at least 18 inches (457 millimeters) of cover in streets and roads. However, where an underground structure prevents installation at those depths, the service line must be able to withstand any anticipated external load.

(b) *Support and backfill.* Each service line must be properly supported on undisturbed or well-compacted soil, and material used for backfill must be free of materials that could damage the pipe or its coating.

(c) *Grading for drainage.* Where condensate in the gas might cause interruption in the gas supply to the customer, the service line must be graded so as to drain into the main or into drips at the low points in the service line.

(d) *Protection against piping strain and external loading.* Each service line must be installed so as to minimize anticipated piping strain and external loading.

(e) *Installation of service lines into buildings.* Each underground service line installed below grade through the outer foundation wall of a building must:

(1) In the case of a metal service line, be protected against corrosion;

(2) In the case of a plastic service line, be protected from shearing action and backfill settlement; and

(3) Be sealed at the foundation wall to prevent leakage into the building.

(f) *Installation of service lines under buildings.* Where an underground service line is installed under a building:

(1) It must be encased in a gas tight conduit;

(2) The conduit and the service line must, if the service line supplies the building it underlies, extend into a normally usable and

accessible part of the building; and

(3) 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, and extend above grade, terminating in a rain and insect resistant fitting.

(g) *Locating underground service lines.* Each underground nonmetallic service line that is not encased must have a means of locating the pipe that complies with §192.321(e).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–75, 61 FR 18517, Apr. 26, 1996; Amdt. 192–85, 63 FR 37503, July 13, 1998; Amdt. 192–93, 68 FR 53900, Sept. 15, 2003]

§192.369 Service lines: Connections to cast iron or ductile iron mains.

(a) Each service line connected to a cast iron or ductile iron main must be connected by a mechanical clamp, by drilling and tapping the main, or by another method meeting the requirements of Sec. 192.273.

(b) If a threaded tap is being inserted, the requirements of Sec. 192.151 (b) and (c) must also be met.

§192.373 Service lines: Cast iron and ductile iron.

(a) Cast or ductile iron pipe less than 6 inches (152 millimeters) in diameter may not be installed for service lines.

(b) If cast iron pipe or ductile iron pipe is installed for use as a service line, the part of the service line which extends through the building wall must be of steel pipe.

(c) A cast iron or ductile iron service line may not be installed in unstable soil or under a building.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37503, July 13, 1998]

§192.489 Remedial measures: Cast iron and ductile iron pipelines.

(a) General graphitization. Each segment of cast iron or ductile iron pipe on which general graphitization is found to a degree where a fracture or any leakage might result, must be replaced.

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

§192.753 Caulked bell and spigot joints.

(a) Each cast iron caulked bell and spigot joint that is subject to pressures of more than 25 psi (172kPa) gage must be sealed with:

(1) A mechanical leak clamp; or

(2) A material or 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 Sec. Sec.

192.53 (a) and (b) and 192.143.

(b) Each cast iron caulked bell and spigot joint that is subject to pressures of 25 psi (172kPa) gage or less and is exposed for any reason must be sealed by a means other than caulking.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-25, 41 FR 23680, June 11, 1976; Amdt. 192-85, 63 FR 37504, July 13, 1998; Amdt. 192-93, 68 FR 53901, Sept. 15, 2003]

§192.755 Protecting cast-iron pipelines.

When an operator has knowledge that the support for a segment of a buried cast-iron pipeline is disturbed:

(a) That segment of the pipeline must be protected, as necessary, against damage during the disturbance by:

(1) Vibrations from heavy construction equipment, trains, trucks, buses, or blasting;

(2) Impact forces by vehicles;

(3) Earth movement;

(4) Apparent future excavations near the pipeline; or

(5) Other foreseeable outside forces which may subject that segment of the pipeline to bending stress.

(b) 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 Sec. Sec. 192.317(a), 192.319, and 192.361(b)-(d).

[Amdt. 192-23, 41 FR 13589, Mar. 31, 1976]

Q. ODORIZING YOUR GAS

PURCHASING ODORIZED GAS

Ohio Rural Natural Gas Co-Op will either purchase gas from the supplying pipeline company that is already odorized or will odorize the gas in accordance with this Section Q. The gas must be odorized to assure that there is enough odorant in the gas so that it is distinctive when gas is present in concentrations in air of one-fifth of the lower explosive limit (LEL). The LEL for Ohio Rural Natural Gas Co-Op 's natural gas is 5 percent gas-in-air by volume; therefore, odorant for natural gas must be present at 1 percent gas-in-air by volume. The lower explosive limit for propane gas is 2.15 percent propane gas-in-air by volume; therefore, odorant for propane gas must be present at 0.43 percent gas-in-air by volume.

The odorant and its product of combustion cannot be toxic to humans or harmful to components that make up your piping system. The odorant may not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight.

ODORIZING GAS

In circumstances where gas is being purchased un-odorized or is insufficiently odorized, Ohio Rural Natural Gas Co-Op shall be responsible for odorizing the gas in accordance with this section. Odorization equipment shall be such as to assure reasonably uniform rates under varying loads and be installed so as not to be a nuisance to adjacent residents. It shall be located so as to assure defused distribution throughout the pipeline system.

PERIODIC SAMPLING.

Ohio Rural Natural Gas Co-Op is responsible for confirmation of adequate odorization. Sites are selected for periodic testing. This is done at various locations near the outer extremities of the pipeline system. The number of sites selected depends on the size and configuration of the system locations of points of delivery and locations of suspected low odorant levels.

An odorometer or odorator will be used for this purpose. Ohio Rural Natural Gas Co-Op will either do this with its own personnel after proper training or will employ an outside consultant.

The frequency should be sufficient to determine that the gas is odorized to the required levels. The actual frequency is:

Four times per calendar year, not to exceed 4-1/2 months.

Ohio Rural Natural Gas Co-Op will provide literature to educate its customers about the smell of natural gas. This will be done on an annual basis.

Ohio Rural Natural Gas Co-Op will maintain records on odor testing. For sample record, see attached.

GAS ODORIZATION CHECK

The odorization of the gas was checked by:

Name	Age	Male/Female

Instrument used:

A Heath Odorator, model number 705637, serial number 2813-5.

ODORIZATION CHECK TABLE

Project name - ________________________________ Reading date - _______________

Person Reading no.			
1st			
2nd			
3rd			
Ave.			

According to the manufacturers literature the:

_______ ave. equates to _______ % gas in air

_______ ave. equates to _______ % gas in air

_______ ave. equates to _______ % gas in air

Temperature _______degrees F,
Wind _______
Time _______AM/PM

Exact location: ____

Inside/Outside: ____

Odorization of Gas

§192.625 Odorization of gas.

(a) A combustible gas in a distribution line must contain a natural odorant or be odorized so that at a concentration in air of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell.

(b) After December 31, 1976, a combustible gas in a transmission line in a Class 3 or Class 4 location must comply with the requirements of paragraph (a) of this section unless:

(1) At least 50 percent of the length of the line downstream from that location is in a Class 1 or Class 2 location;

(2) 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:

(A) Makes the end product unfit for the purpose for which it is intended;

(B) Reduces the activity of a catalyst; or

(C) Reduces the percentage completion of a chemical reaction;

(3) In the case of a lateral line which transports gas to a distribution center, at least 50 percent of the length of that line is in a Class 1 or Class 2 location; or

(4) The combustible gas is hydrogen intended for use as a feedstock in a manufacturing process.

(c) In the concentrations in which it is used, the odorant in combustible gases must comply with the following:

(1) The odorant may not be deleterious to persons, materials, or pipe.

(2) 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.

(d) The odorant may not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight.

(e) Equipment for odorization must introduce the odorant without wide variations in the level of odorant.

(f) To assure the proper concentration of odorant in accordance with this section, each operator must conduct periodic sampling of combustible gases using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable.
Operators of master meter systems may comply with this requirement by--

(1) Receiving written verification from their gas source that the gas has the proper concentration of odorant; and

(2) Conducting periodic ``sniff'' tests at the extremities of the system to confirm that the gas contains odorant.

[35 FR 13257, Aug. 19, 1970 as amended by Amdt. 192-2, 35 FR 17335, Nov. 11, 1970; Amdt. 192-6, 36 FR 25423, Dec. 31, 1971; Amdt. 192-7, 37 FR 17970, Sept. 2, 1972; Amdt. 192-14, 38 FR 14943, June 7, 1973; Amdt. 192-15, 38 FR 35471, Dec. 28, 1973; Amdt. 192-16, 39 FR 45253, Dec. 31, 1974; Amdt. 192-21, 40 FR 20279, May 9, 1975; Amdt. 192-58, 53 FR 1633, Jan. 21, 1988; Amdt. 192-76, 61 FR 26121, May 24, 1996; Amdt. 192-78, 61 FR 28770, June 6, 1996

4.R CONVERSION TO SERVICE

R. CONVERSION TO SERVICE

Pipelines that have been in service not subject to the provisions of 192 may be converted to service under that part if a written study is prepared and documented. All available records should be reviewed. All known unsafe defects and conditions must be corrected in accordance to the requirements of Part 192. This record must be kept on file for the life of the pipeline. The pipeline must be tested in accordance 4.L.7.a of this manual to substantiate the MAOP.

TESTS AND INSPECTIONS

The following are examples of appropriate tests and inspections that may be used to evaluate pipelines where sufficient records are not available .

- corrosion surveys
- ultrasonic inspections
- acoustic emissions
- tensile tests
- internal inspections
- radiographic inspections

Visual inspections of all above ground sections and selected underground segments. Generally the underground segments to be inspected should be at the worst probable conditions. The following criteria should be used in selection of inspection sites.

- where cathodic protection is inadequate or a problem, such as interference is expected.
- pipeline component locations
- locations susceptible of mechanical damage
- foreign pipeline crossing
- locations subject to chemicals such as acids.
- segments subject to coating deterioration due to soil stresses and internal or external temperature extremes.
- population density

§192.14 Conversion to service subject to this part.

(a) A steel pipeline previously used in service not subject to this part qualifies for use under this part 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 this part.

(4) The pipeline must be tested in accordance with subpart J of this part to substantiate the maximum allowable operating pressure permitted by subpart L of this part.

(b) 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 (a) of this section.

[Amdt. 192-30, 42 FR 60148, Nov. 25, 1977]

4.S. TRANSMISSION
LINES & MAINS

S. TRANSMISSION LINES AND MAINS (This section does not apply as Ohio Rural Natural Gas Co-Op has no transmission mains)

Table of Contents

1. Definition
2. General
3. Design Requirements
4. Construction Procedures
5. Operation Practices
6. Maintenance Practices
7. MAOP
8. Records

1. Definition

The Ohio Rural Natural Gas Co-Op Transmission Main is one where the maximum allowable operating pressure (MAOP) creates a hoop stress in the pipe of 20% or more of Specified Minimum Yield Strength (SMYS). Under very special circumstances some plastic lines may be defined as transmission lines.

2. General

When it is necessary to design or operate and maintain a transmission main careful attention shall be given to this procedure, as operation and maintenance practices are different from those associated with distribution mains. This procedure also points out the design and construction requirements that need to be incorporated. It is generally recommended to design piping systems with MAOP's below 20% of SMYS because of the additional O&M requirements. Selecting material of a higher grade than Grade B steel and/or increasing the wall thickness are the simplest methods for designing below 20% of SMYS.

Each transmission line or main must be constructed in accordance with comprehensive written specifications or standards that are consistent with Subpart G of CFR 49 Part 192. Each transmission line or main must also be inspected to ensure that it is constructed in accordance with Subpart G. (Effective 10/1/15, inspection must be performed by someone not participating in the work performed).

Each length of pipe and each other component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability.

3. Design Requirements

The person designing a transmission main shall:

A. Determine the class location, based on Subpart A, Section 192.5 and Section 192.105.

B. Provide for sectionalizing block valves, so that any point on the pipeline is within 2 ½ miles of a valve in a Class 4 location, 4 miles in a Class 3 location, 7 ½ miles in a Class 2 location, and 10 miles in a Class 1 location.

C. Provide each pipe section between block valves with a blow down valve with enough capacity to allow the transmission main to be blown down as rapidly as practicable. Placement of the blow down valve shall be such that it discharges into the atmosphere without creating a hazard. Discharging shall not be into overhead electrical lines and conductors.

D. Provide protection from accidental over pressure. Over pressure protection can be accomplished by one or more of the following:

1. Designing for a MAOP equal to or greater than the supplying source.
2. Monitored regulation.
3. Pressure relief capacity.

E. Test the facility at the maximum test pressure practical in anticipation of future class location changes.

F. Internal corrosion control:

Except for pipelines installed or line pipe, valves, fittings or other line components replaced before May 23, 2007, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line shall have features incorporated into its design and construction by Ohio Rural Natural Gas Co-Op 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:

(1) Be configured to reduce the risk that liquids will collect in the line;

(2) Have effective liquid removal features whenever the configuration would allow liquids to collect; and

(3) Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion.

When the configuration of a transmission line is hanged, Ohio Rural Natural Gas Co-Op shall evaluate the impact of the change on internal corrosion risk to the downstream portion of an existing transmission line and provide for removal of liquids and monitoring of internal corrosion as appropriate.

Ohio Rural Natural Gas Co-Op shall maintain records demonstrating compliance. Provided the records show why incorporating these design features are impracticable or unnecessary, this requirement may be fulfilled through written procedures supported by as-built drawings or other construction records.

Corrosive gas may not be transported by pipeline unless the corrosive effect of the gas on the pipeline has been investigated and steps taken to minimize internal corrosion. Coupons or other suitable means must be used to determine the effectiveness of the steps that are taken. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with intervals not exceeding 7-1/2 months.

Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. Be sure to keep records of this inspection. See the main exposure form for recording this information.

If internal corrosion is found—

(1) The adjacent pipe must be investigated to determine the extent of internal corrosion;

(2) Replacement must be made to the extent required by the applicable paragraphs of §§192.485, 192.487, or 192.489; and

(3) Steps must be taken to minimize the internal corrosion.

G. Passage of Internal Inspection Devices:

(a) Except as provided in (b) and (c) below, 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 by Ohio Rural Natural Gas Co-Op to accommodate the passage of instrumented internal inspection devices.

(b) This section does not apply to:

(1) Manifolds;

(2) Station piping such as at compressor stations, meter stations, or regulator stations;

(3) Piping associated with storage facilities, other than a continuous run of transmission line between a compressor station and storage facilities;

(4) Cross-overs;

(5) Sizes of pipe for which an instrumented internal inspection device is not commercially available;

(6) Transmission lines, operated in conjunction with a distribution system which are installed in Class 4 locations;

(7) Other piping that, under §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.

(c) If emergencies, construction time constraints or other unforeseen construction problems are encountered, Ohio Rural Natural Gas Co-Op need not construct a new or replacement segment of a transmission line to meet paragraph (a) above, if Ohio Rural Natural Gas Co-Op determines and documents why an impracticability prohibits compliance with paragraph (a). Within 30 days after discovering the emergency or construction problem Ohio Rural Natural Gas Co-Op must petition, under §190.9, 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, Ohio Rural Natural Gas Co-Op shall modify that segment to allow passage of instrumented internal inspection devices.

4. Construction Procedures

The following construction procedures shall be practiced:

A. No fittings shall be field fabricated; only manufactured fittings shall be used.
B. Non-destructive testing of welds shall be in accordance with 4.L.4.
C. Pipe shall be field bent to conform to the bottom of the ditch, so as to minimize stresses in the pipe and to protect the coating.
D. Provide at least 12" of clearance from any other underground structure.
E. Install main with a minimum cover as follows:

Location	Normal Soil	Consolidated Rock
Class 1	30 inches	18 inches
Class 2,3,& 4	36 inches	24 inches
Drainage ditches of public Roads and Railroad crossings	36 inches	24 inches

5. Operation Practices

Records

The person responsible for natural gas operations shall establish a system for maintaining a separate file for each transmission main to contain all construction and operation and maintenance records as required by this O&M plan. These records shall include the date, location, and description of any repair due to: imperfection or damage, all leak and repair history, line break repair data, patrol-leakage survey records, valve inspection, odorization test, over pressure inspection, cathodic protection survey, etc. for the life of the pipeline.

Continuing Surveillance

The person responsible for natural gas system operations shall review on an annual basis changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements and other unusual operating and maintenance conditions to determine if a segment of pipe should be reconditioned, phased out, or reduce the maximum allowable operating pressure. This is completed through the course of normal O&M tasks.

The following procedures shall be performed on transmission mains:

A. A patrol program to observe line marker requirements and surface conditions for leakage or construction activity or other factors affecting safety and operations. The interval between patrols shall be as follows:

Class location of line	Maximum intervals between patrols: At highway and railroad crossings	At all other places
1 and 2	7 ½ months; but at least twice each calendar year	15 months; but at least once each calendar year
3	4 ½ months; but at least four times each calendar year	7 ½ months; but at least twice each calendar year
4	4 ½ months; but at least four times each calendar year	4 ½ months; but at least four times each calendar year

B. Leakage surveys shall be conducted at intervals not exceeding 15 months but at least once each calendar year. (For non-odorized gas, leak survey intervals not to exceed 4 ½ months, but at least 4 times each calendar year in Class 4 locations, and not to exceed 7 ½ months, but at least twice each calendar year in Class 3 locations, shall be established.)

C. Abnormal Operation. For Ohio Rural Natural Gas Co-Op 's transmission lines[1], the following procedures will be followed to provide safety when operating design limits have been exceeded:

(1) Ohio Rural Natural Gas Co-Op will respond to, investigate, and correct the cause of:

(a) Unintended closure of valves or shutdowns;

(b) Increase or decrease in pressure or flow rate outside normal operating limits;

(c) Loss of communications;

(d) Operation of any safety device; and

(e) Any other foreseeable malfunction of a component, deviation from normal operation, or personnel error, which may result in a hazard to persons or property.

(2) Ohio Rural Natural Gas Co-Op will check variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation.

(3) Ohio Rural Natural Gas Co-Op will notify responsible operator personnel when notice of an abnormal operation is received.

(4) Ohio Rural Natural Gas Co-Op will periodically review the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.

[1]Does not apply to natural gas distribution operators that are operating transmission lines in connection to their distribution system.

6. Maintenance Practices

Maintenance policies for Ohio Rural Natural Gas Co-Op 's Transmission Mains require that;

A. General Requirements for Repairs

1. No fitting shall be field fabricated, only manufactured fittings shall be used.

2. Weld patches shall not be used as a means of repair, except as noted in the following section on repair of leaks.

3. Regardless of the type of repair the pressure must be at a safe level during repair operations.

4. Immediate temporary measures shall be taken to protect the public whenever a leak, imperfection, or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above 40 percent of the SMYS; and it is not feasible to make a permanent repair at the time of discovery.

5. Permanent repairs shall be made as follows:

(a) Non integrity management repairs: The operator must make permanent repairs as soon as feasible.

(b) Integrity management repairs: When an operator discovers a condition on a pipeline covered under Subpart O–Gas Transmission Pipeline Integrity Management, the operator must remediate the condition as prescribed by §192.933(d).

B. Repair of Imperfections/Damages

(a) Each imperfection or damage that impairs the serviceability of a length of steel pipe must be repaired or removed. If a repair is made by grinding, the remaining wall thickness must at least be equal to either:

(1) The minimum thickness required by the tolerances in the specification to which the pipe was manufactured; or

(2) The nominal wall thickness required for the design pressure of the pipeline.

(b) Each of the following dents must be removed from steel pipe to be operated at a pressure that produces a hoop stress of 20 percent, or more, of SMYS, unless the dent is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe:

(1) A dent that contains a stress concentrator such as a scratch, gouge, groove, or arc burn.

(2) A dent that affects the longitudinal weld or a circumferential weld.

(3) In pipe to be operated at a pressure that produces a hoop stress of 40 percent or more of SMYS, a dent that has a depth of:

(i) More than $\frac{1}{4}$ inch (6.4 millimeters) in pipe $12\frac{3}{4}$ inches (324 millimeters) or less in outer diameter; or

(ii) More than 2 percent of the nominal pipe diameter in pipe over $12\frac{3}{4}$ inches (324 millimeters) in outer diameter.

For the purpose of this section 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.

(c) Each arc burn on steel pipe to be operated at a pressure that produces a hoop stress of 40 percent, 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:

(1) The minimum wall thickness required by the tolerances in the specification to which the pipe was manufactured; or

(2) The nominal wall thickness required for the design pressure of the pipeline.

(d) A gouge, groove, arc burn, or dent may not be repaired by insert patching or by pounding out.

(e) 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.

C. Repair of Welds

1. If possible to take the line out of service: The repair can be made as described in Weld Repair section in the Welding Manual.

2. If the line can't feasibly be taken out of service and it is not leaking, and you can reduce the operating pressure to below 20% of SYMS, and you can keep grinding of the affected area limited so that no less than 0.125" of the weld remains, then you can repair the weld as described in the Weld Repair section in the Welding Manual.

3. If you can't do either of the above then you must make the repair by installing a full encirclement welded split sleeve of the appropriate design.

D. Repair of Leaks.

1. If possible to take the line out of service: A cylindrical section of the affected pipe shall be cut out and replaced with a section of similar or greater strength.

2. If the line can't feasibly be taken out of service:

a. Install a full encirclement welded split sleeve of the appropriate design, unless the pipe is joined by mechanical couplings and operates at less than 40% SMYS.

b. If the leak is due to a corrosion pit, install a bolted leak repair clamp of appropriate design.

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 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.

E. Testing of Repairs

Each segment of pipe repaired by cutting out the damaged portion of the pipe as a cylinder shall 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.

Any repairs made by welding are subject to the same inspection criteria as a new weld as described in the Weld Inspection section in the Welding Manual. For lines 6-inch or larger diameter and that operate at 20% or more of SMYS, tie-in welds must be nondestructively tested according to the standards in Section 9 of API 1104.

F. Other Remedial Measures and Concerns - General and Localized Corrosion.

Whenever a transmission line is encountered with general corrosion and with a remaining wall thickness less than that required for the maximum allowable operating pressure of the pipeline, the corroded area must be replaced or the operating pressure reduced to the point dictated by the strength of the pipe based on actual remaining wall thickness.

However, if the area of general corrosion is small, the corroded pipe may be repaired by a method that reliable engineering tests and analysis show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion.

Whenever a transmission line has localized corrosion pitting to a degree where leakage might result the area must be replaced or repaired, or the operating pressure must be reduced to the point dictated by the strength of the pipe based on actual remaining wall thickness at the location of the pits.

The strength of pipe should be calculated by the procedure in AGA Pipeline Research Committee Project PR 3-805 (with RSTRENG disk). This procedure applies to corroded regions that do not penetrate the pipe wall, subject to the limitations prescribed in the procedures. You may want to consult a specialist as identified at the end of this manual for assistance in this calculation.

7. <u>MAOP</u>

a. Verification of Records (The following is a summary of PHMSA Advisory Notice ADB-12-06)

On January 3, 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Act) was signed which requires PHMSA to direct each owner and operator of a gas transmission pipeline and associated facilities to provide verification that their records accurately reflect MAOP of their pipelines within Class 3 and Class 4 locations and in Class 1 and Class 2 locations in High Consequence Areas (HCA's). Beginning in 2013, PHMSA will require operators to submit data regarding verification of records in their class locations via the Gas Transmission and Gathering Systems Annual Report due June 15, 2013.

Operators should review their records to determine if they are adequate to support operating parameters and conditions on their pipeline systems or if additional action is needed to confirm these parameters and assure safety. In particular, if operators are relying on the review of design, construction, inspection, testing and other related data to establish MAOP as allowed by a method in 49 CFR 192.619, they should assure that the records used are reliable, traceable, verifiable and complete. If such a records search, review and verification cannot be satisfactorily completed, they should not rely on this method for calculating MAOP but instead rely on another method as allowed in Section 192.619.

Section 192.619 currently contains four methods for establishing MAOP; (1) The design pressure of the weakest element in the segment; (2) pressure testing; (3) the highest actual operating pressure in the five years prior to the segment becoming subject to regulation under Part 192; and (4) the maximum safe pressure considering the history of the segment, particularly known corrosion and the actual operating pressure.

The third method, often referred to as the "grandfather clause," allows pipelines that had safely operated prior to the pipeline safety MAOP regulations to continue to operate under similar conditions without retroactively applying recordkeeping requirements or requiring pressure tests. Based on a review of record verification reporting in the 2013 Gas Transmission and Gathering Systems Annual Report, PHMSA may eliminate the "grandfather clause" and require another method of establishing MAOP for older pipelines. Although not yet defined, this could require pressure testing, in-line inspection, reduction of MAOP by 20% or other alternative.

Ohio Rural Natural Gas Co-Op will review their records for establishing MAOP and submit the verification status of this information by June 15, 2013 in their 2012 Annual Report.

b. Alternate Operation at Higher MAOP

Effective December 1, 2008, except in Class 4 locations, Ohio Rural Natural Gas Co-Op has the option of alternatively operating one or more segments of their transmission system at a higher MAOP than formerly allowed.

<u>Calculation of the Alternate MAOP and Test Pressure</u>

Ohio Rural Natural Gas Co-Op calculates the alternate MAOP by using the method in 192.105 but with the higher design factors in 192.620 in place of the design factors in 192.111. For new pipelines, the normal and alternate design factors are:

Class Location	Normal Design Factor	Alternate Design factor
1	.72	.80
2	.60	.67
3	.50	.56

4	.40	N/A

The alternate MAOP is the lower of the following:

(1) The design pressure of the weakest element in the pipeline segment.

(2) The pressure obtained by dividing the pressure to which the pipeline segment was tested after construction by the test factors in 192.620 in place of the test factors in 192.619. For new pipelines, the normal and alternate pressure test factors are:

Class Location	Normal Test Factor	Alternate Test factor
1	1.10	1.25
2	1.25	1.50
3	1.50	1.50
4	1.50	N/A

<u>When Ohio Rural Natural Gas Co-Op May Use the Alternate MAOP</u>

Ohio Rural Natural Gas Co-Op may operate a segment of his transmission system at the alternate MAOP, providing the segment meets the following conditions:

(1) The pipeline segment is in a Class 1, 2 or 3 location.

(2) The pipeline segment is constructed of steel pipe meeting the additional design requirements in 192.112.

(3) A SCADA system provides remote monitoring and control of the pipeline segment.

(4) The pipeline segment meets the additional construction requirements in 192.328.

(5) The pipeline segment does not contain any mechanical couplings used in place of girth welds.

(6) If the pipeline segment has been previously operated, the segment has not experienced any failure during normal operations indicative of a systemic fault in material as determined by a root cause analysis, including metallurgical examination of the failed pipe.

(7) At least 95 percent of girth welds on a segment that was constructed prior to November 17, 2008 must have been non-destructively examined.

<u>What Ohio Rural Natural Gas Co-Op Is Required to Do To Use the Alternate MAOP</u>

Ohio Rural Natural Gas Co-Op must do the following if electing to use the alternate MAOP:

(1) Notify each PHMSA pipeline safety regional office at least 180 days before operation at the alternate MAOP begins.

(2) Certify, by signature of a senior executive officer, that:

(a) The pipeline segment meets the above conditions.
(b) Operating and Maintenance procedures include additional procedures in 192.620.
(c) A review and any needed program upgrade of the damage prevention program required by 192.620 have been completed.

(3) Send a copy of the above certification to the PHMSA pipeline safety regional office and the PUCO at least 30 days before operation at the alternate MAOP begins.
(4) For each pipeline segment, do the following:
    (a) Perform a strength test as described in 192.505 at a test pressure as calculated above, or;
    (b) For a pipeline segment in existence before November 17, 2008, certify that the strength test performed under 192.505 was conducted at a test pressure as calculated above, or conduct a new strength test as calculated above.
(5) Comply with the additional operation and maintenance requirements in 192.620.
(6) If the performance of a construction task associated with implementing alternative MAOP can affect the integrity of the pipeline segment, treat that task as a "covered task" and implement the requirements of 192 Subpart N as appropriate.
(7) Maintain for the useful life of the pipeline records demonstrating compliance with the above.
(8) Class 1 and Class 2 pipeline location can be upgraded one class due to class change per 192.611. Pipelines in Class 4 may not operate at an alternative MAOP.
(9) Overpressure protection:
    (a) Provide overpressure protection that limits mainline pressure to a maximum of 104 percent of the alternate MAOP and;
    (b) Develop and follow a procedure for establishing and maintaining accurate set points for the SCADA system.

8. <u>Records</u>

Each operator shall maintain the following records for transmission lines for the periods specified:

(a) The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipe remains in service.

(b) The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 5 years. However, repairs generated by patrols, surveys, inspections, or tests required by subparts L and M of Part 192 must be retained in accordance with paragraph (c) below.

(c) A record of each patrol, survey, inspection, and test required by subparts L and M of Part 192 must be retained for at least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.

....

§ 192.8 How are onshore gathering lines and regulated onshore gathering lines determined?

(a) An operator must use API RP 80 (incorporated by reference, see §192.7), to determine if an onshore pipeline (or part of a connected series of pipelines) is an onshore gathering line. The determination is subject to the limitations listed below. After making this determination, an operator must determine if the onshore gathering line is a regulated onshore gathering line under paragraph (b) of this section.

(1) The beginning of gathering, under section 2.2(a)(1) of API RP 80, may not extend beyond the furthermost downstream point in a production operation as defined in section 2.3 of API RP 80. This furthermost downstream point does not include equipment that can be used in either production or transportation, such as separators or dehydrators, unless that equipment is involved in the processes of "production and preparation for transportation or delivery of hydrocarbon gas" within the meaning of "production operation."

(2) The endpoint of gathering, under section 2.2(a)(1)(A) of API RP 80, may not extend beyond the first downstream natural gas processing plant, unless the operator can demonstrate, using sound engineering principles, that gathering extends to a further downstream plant.

(3) If the endpoint of gathering, under section 2.2(a)(1)(C) of API RP 80, is determined by the commingling of gas from separate production fields, the fields may not be more than 50 miles from each other, unless the Administrator finds a longer separation distance is justified in a particular case (see 49 CFR §190.9).

(4) The endpoint of gathering, under section 2.2(a)(1)(D) of API RP 80, may not extend beyond the furthermost downstream compressor used to increase gathering line pressure for delivery to another pipeline.

(b) For purposes of §192.9, "regulated onshore gathering line" means:

(1) Each onshore gathering line (or segment of onshore gathering line) with a feature described in the second column that lies in an area described in the third column; and

(2) As applicable, additional lengths of line described in the fourth column to provide a safety buffer:

Type	Feature	Area	Safety buffer
A	—Metallic and the MAOP produces a hoop stress of 20 percent or more of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part	Class 2, 3, or 4 location (*see*§192.5)	None.
	—Non-metallic and the MAOP is more than 125 psig (862 kPa)		
B	—Metallic and the MAOP produces a hoop stress of less than 20 percent of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part —Non-metallic and the MAOP is 125 psig (862 kPa) or less	*Area 1.*Class 3 or 4 location *Area 2.*An area within a Class 2 location the operator determines by using any of the following three methods: (a) A Class 2 location. (b) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1 mile (1.6 km) of pipeline and including more than 10 but	If the gathering line is in Area 2(b) or 2(c), the additional lengths of line extend upstream and downstream from the area to a point where the line is at least 150 feet (45.7 m) from the nearest dwelling in the area. However, if a cluster of dwellings in Area 2 (b) or 2(c) qualifies a line as Type B, the Type B classification ends 150 feet (45.7 m) from the nearest dwelling in the cluster.

		fewer than 46 dwellings (c) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1000 feet (305 m) of pipeline and including 5 or more dwellings	

[Amdt. 192–102, 71 FR 13302, Mar. 15, 2006]

§ 192.9 What requirements apply to gathering lines?

(a) *Requirements.* An operator of a gathering line must follow the safety requirements of this part as prescribed by this section.

(b) *Offshore lines.* An operator of an offshore gathering line must comply with requirements of this part applicable to transmission lines, except the requirements in §192.150 and in subpart O of this part.

(c) *Type A lines.* An operator of a Type A regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in §192.150 and in subpart O of this part. However, an operator of a Type A regulated onshore gathering line in a Class 2 location may demonstrate compliance with subpart N by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks.

(d) *Type B lines.* An operator of a Type B regulated onshore gathering line must comply with the following requirements:

(1) If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this part applicable to transmission lines;

(2) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines;

(3) Carry out a damage prevention program under §192.614;

(4) Establish a public education program under §192.616;

(5) Establish the MAOP of the line under §192.619; and

(6) Install and maintain line markers according to the requirements for transmission lines in §192.707.

(e) *Compliance deadlines.* An operator of a regulated onshore gathering line must comply with the following deadlines, as applicable.

(1) An operator of a new, replaced, relocated, or otherwise changed line must be in compliance with the applicable requirements of this section by the date the line goes into service, unless an exception in §192.13 applies.

(2) If a regulated onshore gathering line existing on April 14, 2006 was not previously subject to this part, an operator has until the date stated in the second column to comply with the applicable requirement for the line listed in the first column, unless the Administrator finds a later deadline is justified in a particular case:

Requirement	Compliance deadline
Control corrosion according to Subpart I requirements for transmission lines	April 15, 2009.
Carry out a damage prevention program under §192.614	October 15, 2007.
Establish MAOP under §192.619	October 15, 2007.
Install and maintain line markers under §192.707	April 15, 2008.
Establish a public education program under §192.616	April 15, 2008.
Other provisions of this part as required by paragraph (c) of this section for Type A lines	April 15, 2009.

(3) If, after April 14, 2006, a change in class location or increase in dwelling density causes an onshore gathering line to be a regulated onshore gathering line, the operator has 1 year for Type B lines and 2 years for Type A lines after the line becomes a regulated onshore gathering line to comply with this section.

[Amdt. 192–102, 71 FR 13301, Mar. 15, 2006]

§192.112 Additional design requirements for steel pipe using alternative maximum allowable operating pressure.

Link to an amendment published at 80 FR 12777, March 11, 2015.

For a new or existing pipeline segment to be eligible for operation at the alternative maximum allowable operating pressure (MAOP) calculated under §192.620, a segment must meet the following additional design requirements. Records for alternative MAOP must be maintained, for the useful life of the pipeline, demonstrating compliance with these requirements:

To address this design issue:	The pipeline segment must meet these additional requirements:
(a) General standards for the steel pipe	(1) The plate, skelp, or coil used for the pipe must be micro-alloyed, fine grain, fully killed, continuously cast steel with calcium treatment.
	(2) The carbon equivalents of the steel used for pipe must not exceed 0.25 percent by weight, as calculated by the Ito-Bessyo formula (Pcm formula) or 0.43 percent by weight, as calculated by the International Institute of Welding (IIW) formula.
	(3) The ratio of the specified outside diameter of the pipe to the specified wall thickness must be less than 100. The wall thickness or other mitigative measures must prevent denting and ovality anomalies during construction, strength testing and anticipated operational stresses.
	(4) The pipe must be manufactured using API Spec 5L, product specification level 2 (incorporated by reference, see §192.7) for maximum operating pressures and minimum and maximum operating temperatures and other requirements under this section.
(b) Fracture control	(1) The toughness properties for pipe must address the potential for initiation, propagation and arrest of fractures in accordance with:
	(i) API Spec 5L (incorporated by reference, see §192.7); or
	(ii) American Society of Mechanical Engineers (ASME) B31.8 (incorporated by reference, see §192.7); and
	(iii) Any correction factors needed to address pipe grades, pressures, temperatures, or gas compositions not expressly addressed in API Spec 5L , product specification level 2 or ASME B31.8 (incorporated by reference, see §192.7).
	(2) Fracture control must:
	(i) Ensure resistance to fracture initiation while addressing the full range of operating temperatures, pressures, gas compositions, pipe grade and operating stress levels, including maximum pressures and minimum temperatures for shut-in conditions, that the pipeline is expected to experience. If these parameters change during operation of the pipeline such that they are outside the bounds of what was considered in the design evaluation, the evaluation must be reviewed and updated to assure continued resistance to fracture initiation over the operating life of the pipeline;
	(ii) Address adjustments to toughness of pipe for each grade used and the decompression behavior of the gas at operating parameters;
	(iii) Ensure at least 99 percent probability of fracture arrest within eight pipe lengths with a probability of not less than 90 percent within five pipe lengths; and
	(iv) Include fracture toughness testing that is equivalent to that described in supplementary requirements SR5A, SR5B, and SR6 of API Specification 5L (incorporated by reference, see §192.7) and ensures ductile fracture and arrest with the following exceptions:

	(A) The results of the Charpy impact test prescribed in SR5A must indicate at least 80 percent minimum shear area for any single test on each heat of steel; and
	(B) The results of the drop weight test prescribed in SR6 must indicate 80 percent average shear area with a minimum single test result of 60 percent shear area for any steel test samples. The test results must ensure a ductile fracture and arrest.
	(3) If it is not physically possible to achieve the pipeline toughness properties of paragraphs (b)(1) and (2) of this section, additional design features, such as mechanical or composite crack arrestors and/or heavier walled pipe of proper design and spacing, must be used to ensure fracture arrest as described in paragraph (b)(2)(iii) of this section.
(c) Plate/coil quality control	(1) There must be an internal quality management program at all mills involved in producing steel, plate, coil, skelp, and/or rolling pipe to be operated at alternative MAOP. These programs must be structured to eliminate or detect defects and inclusions affecting pipe quality.
	(2) A mill inspection program or internal quality management program must include (i) and either (ii) or (iii):
	(i) An ultrasonic test of the ends and at least 35 percent of the surface of the plate/coil or pipe to identify imperfections that impair serviceability such as laminations, cracks, and inclusions. At least 95 percent of the lengths of pipe manufactured must be tested. For all pipelines designed after December 22, 2008, the test must be done in accordance with ASTM A578/A578M Level B, or API Spec 5L Paragraph 7.8.10 (incorporated by reference, see §192.7) or equivalent method, and either
	(ii) A macro etch test or other equivalent method to identify inclusions that may form centerline segregation during the continuous casting process. Use of sulfur prints is not an equivalent method. The test must be carried out on the first or second slab of each sequence graded with an acceptance criteria of one or two on the Mannesmann scale or equivalent; or
	(iii) A quality assurance monitoring program implemented by the operator that includes audits of: (a) all steelmaking and casting facilities, (b) quality control plans and manufacturing procedure specifications, (c) equipment maintenance and records of conformance, (d) applicable casting superheat and speeds, and (e) centerline segregation monitoring records to ensure mitigation of centerline segregation during the continuous casting process.
(d) Seam quality control	(1) There must be a quality assurance program for pipe seam welds to assure tensile strength provided in API Spec 5L (incorporated by reference, see §192.7) for appropriate grades.
	(2) There must be a hardness test, using Vickers (Hv10) hardness test method or equivalent test method, to assure a maximum hardness of 280 Vickers of the following:
	(i) A cross section of the weld seam of one pipe from each heat plus one pipe from each welding line per day; and
	(ii) For each sample cross section, a minimum of 13 readings (three for each heat affected zone, three in the weld metal, and two in each section of pipe base metal).
	(3) All of the seams must be ultrasonically tested after cold expansion and mill hydrostatic testing.
(e) Mill hydrostatic test	(1) All pipe to be used in a new pipeline segment must be hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 95 percent SMYS for 10 seconds. The test pressure may include a combination of internal test pressure and the allowance for end loading stresses imposed by the pipe mill hydrostatic testing equipment as allowed by API Spec 5L , Appendix K (incorporated by reference, see §192.7).
	(2) Pipe in operation prior to December 22, 2008, must have been hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 90 percent SMYS for 10 seconds.
(f) Coating	(1) The pipe must be protected against external corrosion by a non-shielding coating.
	(2) Coating on pipe used for trenchless installation must be non-shielding and resist abrasions and other damage possible during installation.
	(3) A quality assurance inspection and testing program for the coating must cover the surface quality of the bare pipe, surface cleanliness and chlorides, blast cleaning, application temperature control, adhesion, cathodic disbondment, moisture permeation, bending, coating thickness, holiday detection, and repair.

(g) Fittings and flanges	(1) There must be certification records of flanges, factory induction bends and factory weld ells. Certification must address material properties such as chemistry, minimum yield strength and minimum wall thickness to meet design conditions.
	(2) If the carbon equivalents of flanges, bends and ells are greater than 0.42 percent by weight, the qualified welding procedures must include a pre-heat procedure.
	(3) Valves, flanges and fittings must be rated based upon the required specification rating class for the alternative MAOP.
(h) Compressor stations	(1) A compressor station must be designed to limit the temperature of the nearest downstream segment operating at alternative MAOP to a maximum of 120 degrees Fahrenheit (49 degrees Celsius) or the higher temperature allowed in paragraph (h)(2) of this section unless a long-term coating integrity monitoring program is implemented in accordance with paragraph (h)(3) of this section.
	(2) If research, testing and field monitoring tests demonstrate that the coating type being used will withstand a higher temperature in long-term operations, the compressor station may be designed to limit downstream piping to that higher temperature. Test results and acceptance criteria addressing coating adhesion, cathodic disbondment, and coating condition must be provided to each PHMSA pipeline safety regional office where the pipeline is in service at least 60 days prior to operating above 120 degrees Fahrenheit (49 degrees Celsius). An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.
	(3) Pipeline segments operating at alternative MAOP may operate at temperatures above 120 degrees Fahrenheit (49 degrees Celsius) if the operator implements a long-term coating integrity monitoring program. The monitoring program must include examinations using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or an equivalent method of monitoring coating integrity. An operator must specify the periodicity at which these examinations occur and criteria for repairing identified indications. An operator must submit its long-term coating integrity monitoring program to each PHMSA pipeline safety regional office in which the pipeline is located for review before the pipeline segments may be operated at temperatures in excess of 120 degrees Fahrenheit (49 degrees Celsius). An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.

[73 FR 62175, Oct. 17, 2008, as amended by Amdt. 192-111, 74 FR 62505, Nov. 30, 2009; Amdt. 192-119, 80 FR 180, Jan. 5, 2015]

§ 192.150 Passage of internal inspection devices.

(a) Except as provided in paragraphs (b) and (c) of this section, 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 instrumented internal inspection devices.

(b) This section does not apply to: (1) Manifolds;

(2) Station piping such as at compressor stations, meter stations, or regulator stations;

(3) Piping associated with storage facilities, other than a continuous run of transmission line between a compressor station and storage facilities;

(4) Cross-overs;

(5) Sizes of pipe for which an instrumented internal inspection device is not commercially available;

(6) Transmission lines, operated in conjunction with a distribution system which are installed in Class 4 locations;

(7) Offshore transmission lines, except transmission lines 103/4inches (273 millimeters) or more in outside diameter on which construction begins after December 28, 2005, that run from platform to platform or platform to shore unless—

(i) Platform space or configuration is incompatible with launching or retrieving instrumented internal inspection devices; or

(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

(8) Other piping that, under §190.9 of this chapter, the Administrator finds in a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices.

(c) 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 (a) of this section, if the operator determines and documents why an impracticability prohibits compliance with paragraph (a) 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.

[Amdt. 192–72, 59 FR 17281, Apr. 12, 1994, as amended by Amdt. 192–85, 63 FR 37502, July 13, 1998; Amdt. 192–97, 69 FR 36029, June 28, 2004]

Subpart G—General Construction Requirements for Transmission Lines and Mains

§ 192.301 Scope.

This subpart prescribes minimum requirements for constructing transmission lines and mains.

§ 192.303 Compliance with specifications or standards.

Each transmission line or main must be constructed in accordance with comprehensive written specifications or standards that are consistent with this part.

§192.309 Repair of steel pipe.

(a) Each imperfection or damage that impairs the serviceability of a length of steel pipe must be repaired or removed. If a repair is made by grinding, the remaining wall thickness must at least be equal to either:

(1) The minimum thickness required by the tolerances in the specification to which the pipe was manufactured; or

(2) The nominal wall thickness required for the design pressure of the pipeline.

(b) Each of the following dents must be removed from steel pipe to be operated at a pressure that produces a hoop stress of 20 percent, or more, of SMYS, unless the dent is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe:

(1) A dent that contains a stress concentrator such as a scratch, gouge, groove, or arc burn.

(2) A dent that affects the longitudinal weld or a circumferential weld.

(3) In pipe to be operated at a pressure that produces a hoop stress of 40 percent or more of SMYS, a dent that has a depth of:

(i) More than $\frac{1}{4}$ inch (6.4 millimeters) in pipe $12\frac{3}{4}$ inches (324 millimeters) or less in outer diameter; or

(ii) More than 2 percent of the nominal pipe diameter in pipe over $12\frac{3}{4}$ inches (324 millimeters) in outer diameter.

For the purpose of this section 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.

(c) Each arc burn on steel pipe to be operated at a pressure that produces a hoop stress of 40 percent, 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:

(1) The minimum wall thickness required by the tolerances in the specification to which the pipe was manufactured; or

(2) The nominal wall thickness required for the design pressure of the pipeline.

(d) A gouge, groove, arc burn, or dent may not be repaired by insert patching or by pounding out.

(e) 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.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-88, 64 FR 69664, Dec. 14, 1999]

§ 192.305 Inspection: General.

Each transmission line or main must be inspected to ensure that it is constructed in accordance with this part.

§ 192.327 Cover.

(a) Except as provided in paragraphs (c), (e), (f), and (g) of this section, each buried transmission line must be installed with a minimum cover as follows:

Location	Normal soil	Consolidated rock
Inches (Millimeters)		
Class 1 locations	30 (762)	18 (457)
Class 2, 3, and 4 locations	36 (914)	24 (610)
Drainage ditches of public roads and railroad crossings	36 (914)	24 (610)

(b) Except as provided in paragraphs (c) and (d) of this section, each buried main must be installed with at least 24 inches (610 millimeters) of cover.

(c) Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.

(d) A main may be installed with less than 24 inches (610 millimeters) of cover if the law of the State or municipality:

(1) Establishes a minimum cover of less than 24 inches (610 millimeters);

(2) Requires that mains be installed in a common trench with other utility lines; and

(3) Provides adequately for prevention of damage to the pipe by external forces.

(e) Except as provided in paragraph (c) of this section, all pipe installed in a navigable river, stream, or harbor must be installed with a minimum cover of 48 inches (1,219 millimeters) in soil or 24 inches (610 millimeters) in consolidated rock between the of the pipe and the underwater natural bottom (as determined by recognized and generally accepted practices).

(f) All pipe installed offshore, except in the Gulf of Mexico and its inlets, under water not more than 200 feet (60 meters) deep, as measured from the mean low tide, must be installed as follows:

(1) Except as provided in paragraph (c) of this section, pipe under water less than 12 feet (3.66 meters) deep, must be installed with a minimum cover of 36 inches (914 millimeters) in soil or 18 inches (457 millimeters) in consolidated rock between the of the pipe and the natural bottom.

(2) Pipe under water at least 12 feet (3.66 meters) deep must be installed so that the of the pipe is below the natural bottom, unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means.

(g) All pipelines installed under water in the Gulf of Mexico and its inlets, as defined in §192.3, must be installed in accordance with §192.612(b)(3).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–27, 41 FR 34606, Aug. 16, 1976; Amdt. 192–78, 61 FR 28785, June 6, 1996;

Amdt. 192–85, 63 FR 37503, July 13, 1998; Amdt. 192–98, 69 FR 48406, Aug. 10, 2004]

§ 192.328 Additional construction requirements for steel pipe using alternative maximum allowable operating pressure.

For a new or existing pipeline segment to be eligible for operation at the alternative maximum allowable operating pressure calculated under §192.620, a segment must meet the following additional construction requirements. Records must be maintained, for the useful life of the pipeline, demonstrating compliance with these requirements:

To address this construction issue:	The pipeline segment must meet this additional construction requirement:
(a) Quality assurance	(1) The construction of the pipeline segment must be done under a quality assurance plan addressing pipe inspection, hauling and stringing, field bending, welding, non-destructive examination of girth welds, applying and testing field applied coating, lowering of the pipeline into the ditch, padding and backfilling, and hydrostatic testing.
	(2) The quality assurance plan for applying and testing field applied coating to girth welds must be:
	(i) Equivalent to that required under §192.112(f)(3) for pipe; and
	(ii) Performed by an individual with the knowledge, skills, and ability to assure effective coating application.
(b) Girth welds	(1) All girth welds on a new pipeline segment must be non-destructively examined in accordance with §192.243(b) and (c).
(c) Depth of cover	(1) Notwithstanding any lesser depth of cover otherwise allowed in §192.327, there must be at least 36 inches (914 millimeters) of cover or equivalent means to protect the pipeline from outside force damage.
	(2) In areas where deep tilling or other activities could threaten the pipeline, the top of the pipeline must be installed at least one foot below the deepest expected penetration of the soil.
(d) Initial strength testing	(1) The pipeline segment must not have experienced failures indicative of systemic material defects during strength testing, including initial hydrostatic testing. A root cause analysis, including metallurgical examination of the failed pipe, must be performed for any failure experienced to verify that it is not indicative of a systemic concern. The results of this root cause analysis must be reported to each PHMSA pipeline safety regional office where the pipe is in service at least 60 days prior to operating at the alternative MAOP. An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.
(e) Interference currents	(1) For a new pipeline segment, the construction must address the impacts of induced alternating current from parallel electric transmission lines and other known sources of potential interference with corrosion control.

[72 FR 62176, Oct. 17, 2008]

§ 192.476 Internal corrosion control: Design and construction of transmission line.

(a) *Design and construction.* Except as provided in paragraph (b) 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:

(1) Be configured to reduce the risk that liquids will collect in the line;

(2) Have effective liquid removal features whenever the configuration would allow liquids to collect; and

(3) Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion.

(b) *Exceptions to applicability.* The design and construction requirements of paragraph (a) of this section do not apply to the following:

(1) Offshore pipeline; and

(2) Pipeline installed or line pipe, valve, fitting or other line component replaced before May 23, 2007.

(c) *Change to existing transmission line.* 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.

(d) *Records.* An operator must maintain records demonstrating compliance with this section. Provided the records show why incorporating design features addressing paragraph (a)(1), (a)(2), or (a)(3) of this section is impracticable or unnecessary, an operator may fulfill this requirement through written procedures supported by as-built drawings or other construction records.

[72 FR 20059, Apr. 23, 2007]

§192.485 Remedial measures: Transmission lines.

(a) *General corrosion.* Each segment of transmission line with general corrosion and 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. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) *Localized corrosion pitting.* 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.

(c) Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G (incorporated by reference, *see* §192.7) or the procedure in PRCI PR 3-805 (R-STRENG) (incorporated by reference, see §192.7). Both procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations prescribed in the procedures.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978; Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt. 192-88, 64 FR 69664, Dec. 14, 1999; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§ 192.605 Procedural manual for operations, maintenance, and emergencies.

(a) *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 reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year. This manual must be prepared before operations of a pipeline system commence. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.

(b) *Maintenance and normal operations.* The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations.

(1) Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this subpart and subpart M of this part.

(2) Controlling corrosion in accordance with the operations and maintenance requirements of subpart I of this part.

(3) Making construction records, maps, and operating history available to appropriate operating personnel.

(4) Gathering of data needed for reporting incidents under Part 191 of this chapter in a timely and effective manner.

(5) Starting up and shutting down any part of the pipeline in a manner designed to assure operation within the MAOP limits prescribed by this part, plus the build-up allowed for operation of pressure-limiting and control devices.

(6) Maintaining compressor stations, including provisions for isolating units or sections of pipe and for purging before returning to service.

(7) Starting, operating and shutting down gas compressor units.

(8) 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.

(9) 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 a breathing apparatus and, a rescue harness and line.

(10) Systematic and routine testing and inspection of pipe-type or bottle-type holders including—

(i) Provision for detecting external corrosion before the strength of the container has been impaired;

(ii) Periodic sampling and testing of gas in storage to determine the dew point of vapors contained in the stored gas which, if condensed, might cause internal corrosion or interfere with the safe operation of the storage plant; and

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

(11) Responding promptly to a report of a gas odor inside or near a building, unless the operator's emergency procedures under §192.615(a)(3) specifically apply to these reports.

(12) Implementing the applicable control room management procedures required by §192.631.

(c) *Abnormal operation.* For transmission lines, the manual required by paragraph (a) of this section must include procedures for the following to provide safety when operating design limits have been exceeded:

(1) Responding to, investigating, and correcting the cause of:

(i) Unintended closure of valves or shutdowns;

(ii) Increase or decrease in pressure or flow rate outside normal operating limits;

(iii) Loss of communications;

(iv) Operation of any safety device; and

(v) Any other foreseeable malfunction of a component, deviation from normal operation, or personnel error, which may result in a hazard to persons or property.

(2) Checking variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation.

(3) Notifying responsible operator personnel when notice of an abnormal operation is received.

(4) Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.

(5) The requirements of this paragraph (c) do not apply to natural gas distribution operators that are operating transmission lines in connection with their distribution system.

(d) *Safety-related condition reports.* The manual required by paragraph (a) of this section 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 §191.23 of this subchapter.

(e) *Surveillance, emergency response, and accident investigation.* The procedures required by §§192.613(a), 192.615, and 192.617 must be included in the manual required by paragraph (a) of this section.

[Amdt. 192–71, 59 FR 6584, Feb. 11, 1994, as amended by Amdt. 192–71A, 60 FR 14381, Mar. 17, 1995; Amdt. 192–93, 68 FR 53901, Sept. 15, 2003; Amdt. 192–112, 74 FR 63327, Dec. 3, 2009]

§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure determined under paragraph (c) or (d) of this section, or the lowest of the following:

(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part. However, for steel pipe in pipelines being converted under §192.14 or uprated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§192.105) is unknown, one of the following pressures is to be used as design pressure:

(i) Eighty percent of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8 (incorporated by reference, *see* §192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or

(ii) If the pipe is 123/4inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).

(2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:

Class location	Factors[1], segment—		
	Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970)	Converted under §192.14
1	1.1	1.1	1.25
2	1.25	1.25	1.25
3	1.4	1.5	1.5
4	1.4	1.5	1.5

[1]For offshore segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

(3) 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 in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	Pressure date	Test date
—Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006	March 15, 2006, or date line becomes subject to this part, whichever is later	5 years preceding applicable date in second column.
—Onshore transmission line that was a gathering line not subject to this part before March 15, 2006		
Offshore gathering lines	July 1, 1976	July 1, 1971.
All other pipelines	July 1, 1970	July 1, 1965.

(4) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.

(b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §192.195.

(c) 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 the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with §192.611.

(d) 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 maximum allowable operating pressure determined under §192.620(a).

[35 FR 13257, Aug. 19, 1970]

§ 192.620 Alternative maximum allowable operating pressure for certain steel pipelines.

(a) *How does an operator calculate the alternative maximum allowable operating pressure?* An operator calculates the alternative maximum allowable operating pressure by using different factors in the same formulas used for calculating maximum allowable operating pressure under §192.619(a) as follows:

(1) In determining the alternative design pressure under §192.105, use a design factor determined in accordance with §192.111(b), (c), or (d) or, if none of these paragraphs apply, in accordance with the following table:

Class location	Alternative design factor (F)
1	0.80
2	0.67
3	0.56

(i) For facilities installed prior to December 22, 2008, for which §192.111(b), (c), or (d) applies, use the following design factors as alternatives for the factors specified in those paragraphs: §192.111(b)–0.67 or less; 192.111(c) and (d)–0.56 or less.

(ii) [Reserved]

(2) The alternative maximum allowable operating pressure is the lower of the following:

(i) The design pressure of the weakest element in the pipeline segment, determined under subparts C and D of this part.

(ii) The pressure obtained by dividing the pressure to which the pipeline segment was tested after construction by a factor determined in the following table:

Class location	Alternative test factor
1	1.25
2	[1]1.50
3	1.50

[1]For Class 2 alternative maximum allowable operating pressure segments installed prior to December 22, 2008 the alternative test factor is 1.25.

(b) *When may an operator use the alternative maximum allowable operating pressure calculated under paragraph (a) of this section?* An operator may use an alternative maximum allowable operating pressure calculated under paragraph (a) of this section if the following conditions are met:

(1) The pipeline segment is in a Class 1, 2, or 3 location;

(2) The pipeline segment is constructed of steel pipe meeting the additional design requirements in §192.112;

(3) A supervisory control and data acquisition system provides remote monitoring and control of the pipeline segment. The control provided must include monitoring of pressures and flows, monitoring compressor start-ups and shut-downs, and remote closure of valves per paragraph (d)(3) of this section;

(4) The pipeline segment meets the additional construction requirements described in §192.328;

(5) The pipeline segment does not contain any mechanical couplings used in place of girth welds;

(6) If a pipeline segment has been previously operated, the segment has not experienced any failure during normal operations indicative of a systemic fault in material as determined by a root cause analysis, including metallurgical examination of the failed pipe. The results of this root cause analysis must be reported to each PHMSA pipeline safety regional office where the pipeline is in service at least 60 days prior to operation at the alternative MAOP. An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State; and

(7) At least 95 percent of girth welds on a segment that was constructed prior to December 22, 2008, must have been non-destructively examined in accordance with §192.243(b) and (c).

(c) *What is an operator electing to use the alternative maximum allowable operating pressure required to do?* If an operator elects to use the alternative maximum allowable operating pressure calculated under paragraph (a) of this section for a pipeline segment, the operator must do each of the following:

(1) Notify each PHMSA pipeline safety regional office where the pipeline is in service of its election with respect to a segment at least 180 days before operating at the alternative maximum allowable operating pressure. An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.

(2) Certify, by signature of a senior executive officer of the company, as follows:

(i) The pipeline segment meets the conditions described in paragraph (b) of this section; and

(ii) The operating and maintenance procedures include the additional operating and maintenance requirements of paragraph (d) of this section; and

(iii) The review and any needed program upgrade of the damage prevention program required by paragraph (d)(4)(v) of this section has been completed.

(3) Send a copy of the certification required by paragraph (c)(2) of this section to each PHMSA pipeline safety regional office where the pipeline is in service 30 days prior to operating at the alternative MAOP. An operator must also send a copy to a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.

(4) For each pipeline segment, do one of the following:

(i) Perform a strength test as described in §192.505 at a test pressure calculated under paragraph (a) of this section or

(ii) For a pipeline segment in existence prior to December 22, 2008, certify, under paragraph (c)(2) of this section, that the strength test performed under §192.505 was conducted at test pressure calculated under paragraph (a) of this section, or conduct a new strength test in accordance with paragraph (c)(4)(i) of this section.

(5) Comply with the additional operation and maintenance requirements described in paragraph (d) of this section.

(6) If the performance of a construction task associated with implementing alternative MAOP that occurs after December 22, 2008, can affect the integrity of the pipeline segment, treat that task as a "covered task", notwithstanding the definition in §192.801 (b) and implement the requirements of subpart N as appropriate.

(7) Maintain, for the useful life of the pipeline, records demonstrating compliance with paragraphs (b), (c)(6), and (d) of this section.

(8) A Class 1 and Class 2 pipeline location can be upgraded one class due to class changes per §192.611(a)(3)(i). All class location changes from Class 1 to Class 2 and from Class 2 to Class 3 must have all anomalies evaluated and remediated per: The "original

pipeline class grade" §192.620(d)(11) anomaly repair requirements; and all anomalies with a wall loss equal to or greater than 40 percent must be excavated and remediated. Pipelines in Class 4 may not operate at an alternative MAOP.

(d) *What additional operation and maintenance requirements apply to operation at the alternative maximum allowable operating pressure?* In addition to compliance with other applicable safety standards in this part, if an operator establishes a maximum allowable operating pressure for a pipeline segment under paragraph (a) of this section, an operator must comply with the additional operation and maintenance requirements as follows:

To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:	Take the following additional step:
(1) Identifying and evaluating threats	Develop a threat matrix consistent with §192.917 to do the following: (i) Identify and compare the increased risk of operating the pipeline at the increased stress level under this section with conventional operation; and
	(ii) Describe and implement procedures used to mitigate the risk.
(2) Notifying the public	(i) Recalculate the potential impact circle as defined in §192.903 to reflect use of the alternative maximum operating pressure calculated under paragraph (a) of this section and pipeline operating conditions; and
	(ii) In implementing the public education program required under §192.616, perform the following:
	(A) Include persons occupying property within 220 yards of the centerline and within the potential impact circle within the targeted audience; and
	(B) Include information about the integrity management activities performed under this section within the message provided to the audience.
(3) Responding to an emergency in an area defined as a high consequence area in §192.903	(i) Ensure that the identification of high consequence areas reflects the larger potential impact circle recalculated under paragraph (d)(2)(i) of this section.
	(ii) If personnel response time to mainline valves on either side of the high consequence area exceeds one hour (under normal driving conditions and speed limits) from the time the event is identified in the control room, provide remote valve control through a supervisory control and data acquisition (SCADA) system, other leak detection system, or an alternative method of control.
	(iii) Remote valve control must include the ability to close and monitor the valve position (open or closed), and monitor pressure upstream and downstream.
	(iv) A line break valve control system using differential pressure, rate of pressure drop or other widely-accepted method is an acceptable alternative to remote valve control.
(4) Protecting the right-of-way	(i) Patrol the right-of-way at intervals not exceeding 45 days, but at least 12 times each calendar year, to inspect for excavation activities, ground movement, wash outs, leakage, or other activities or conditions affecting the safety operation of the pipeline.
	(ii) Develop and implement a plan to monitor for and mitigate occurrences of unstable soil and ground movement.
	(iii) If observed conditions indicate the possible loss of cover, perform a depth of cover study and replace cover as necessary to restore the depth of cover or apply alternative means to provide protection equivalent to the originally-required depth of cover.
	(iv) Use line-of-sight line markers satisfying the requirements of §192.707(d) except in agricultural areas, large water crossings or swamp, steep terrain, or where prohibited by Federal Energy Regulatory Commission orders, permits, or local law.
	(v) Review the damage prevention program under §192.614(a) in light of national consensus practices, to ensure the program provides adequate protection of the right-of-way. Identify the

	standards or practices considered in the review, and meet or exceed those standards or practices by incorporating appropriate changes into the program.
	(vi) Develop and implement a right-of-way management plan to protect the pipeline segment from damage due to excavation activities.
(5) Controlling internal corrosion	(i) Develop and implement a program to monitor for and mitigate the presence of, deleterious gas stream constituents.
	(ii) At points where gas with potentially deleterious contaminants enters the pipeline, use filter separators or separators and gas quality monitoring equipment.
	(iii) Use gas quality monitoring equipment that includes a moisture analyzer, chromatograph, and periodic hydrogen sulfide sampling.
	(iv) Use cleaning pigs and sample accumulated liquids. Use inhibitors when corrosive gas or liquids are present.
	(v) Address deleterious gas stream constituents as follows:
	(A) Limit carbon dioxide to 3 percent by volume;
	(B) Allow no free water and otherwise limit water to seven pounds per million cubic feet of gas; and
	(C) Limit hydrogen sulfide to 1.0 grain per hundred cubic feet (16 ppm) of gas, where the hydrogen sulfide is greater than 0.5 grain per hundred cubic feet (8 ppm) of gas, implement a pigging and inhibitor injection program to address deleterious gas stream constituents, including follow-up sampling and quality testing of liquids at receipt points.
	(vi) Review the program at least quarterly based on the gas stream experience and implement adjustments to monitor for, and mitigate the presence of, deleterious gas stream constituents.
(6) Controlling interference that can impact external corrosion	(i) Prior to operating an existing pipeline segment at an alternate maximum allowable operating pressure calculated under this section, or within six months after placing a new pipeline segment in service at an alternate maximum allowable operating pressure calculated under this section, address any interference currents on the pipeline segment.
	(ii) To address interference currents, perform the following:
	(A) Conduct an interference survey to detect the presence and level of any electrical current that could impact external corrosion where interference is suspected;
	(B) Analyze the results of the survey; and
	(C) Take any remedial action needed within 6 months after completing the survey to protect the pipeline segment from deleterious current.
(7) Confirming external corrosion control through indirect assessment	(i) Within six months after placing the cathodic protection of a new pipeline segment in operation, or within six months after certifying a segment under §192.620(c)(1) of an existing pipeline segment under this section, assess the adequacy of the cathodic protection through an indirect method such as close-interval survey, and the integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG).
	(ii) Remediate any construction damaged coating with a voltage drop classified as moderate or severe (IR drop greater than 35% for DCVG or 50 dBμv for ACVG) under section 4 of NACE RP–0502–2002 (incorporated by reference, see §192.7).
	(iii) Within six months after completing the baseline internal inspection required under paragraph (d)(9) of this section, integrate the results of the indirect assessment required under paragraph (d)(7)(i) of this section with the results of the baseline internal inspection and take any needed remedial actions.

	(iv) For all pipeline segments in high consequence areas, perform periodic assessments as follows:
	(A) Conduct periodic close interval surveys with current interrupted to confirm voltage drops in association with periodic assessments under subpart O of this part.
	(B) Locate pipe-to-soil test stations at half-mile intervals within each high consequence area ensuring at least one station is within each high consequence area, if practicable.
	(C) Integrate the results with those of the baseline and periodic assessments for integrity done under paragraphs (d)(9) and (d)(10) of this section.
(8) Controlling external corrosion through cathodic protection	(i) If an annual test station reading indicates cathodic protection below the level of protection required in subpart I of this part, complete remedial action within six months of the failed reading or notify each PHMSA pipeline safety regional office where the pipeline is in service demonstrating that the integrity of the pipeline is not compromised if the repair takes longer than 6 months. An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State; and
	(ii) After remedial action to address a failed reading, confirm restoration of adequate corrosion control by a close interval survey on either side of the affected test station to the next test station unless the reason for the failed reading is determined to be a rectifier connection or power input problem that can be remediated and otherwise verified.
	(iii) If the pipeline segment has been in operation, the cathodic protection system on the pipeline segment must have been operational within 12 months of the completion of construction.
(9) Conducting a baseline assessment of integrity	(i) Except as provided in paragraph (d)(9)(iii) of this section, for a new pipeline segment operating at the new alternative maximum allowable operating pressure, perform a baseline internal inspection of the entire pipeline segment as follows:
	(A) Assess using a geometry tool after the initial hydrostatic test and backfill and within six months after placing the new pipeline segment in service; and
	(B) Assess using a high resolution magnetic flux tool within three years after placing the new pipeline segment in service at the alternative maximum allowable operating pressure.
	(ii) Except as provided in paragraph (d)(9)(iii) of this section, for an existing pipeline segment, perform a baseline internal assessment using a geometry tool and a high resolution magnetic flux tool before, but within two years prior to, raising pressure to the alternative maximum allowable operating pressure as allowed under this section.
	(iii) If headers, mainline valve by-passes, compressor station piping, meter station piping, or other short portion of a pipeline segment operating at alternative maximum allowable operating pressure cannot accommodate a geometry tool and a high resolution magnetic flux tool, use direct assessment (per §192.925, §192.927 and/or §192.929) or pressure testing (per subpart J of this part) to assess that portion.
(10) Conducting periodic assessments of integrity	(i) Determine a frequency for subsequent periodic integrity assessments as if all the alternative maximum allowable operating pressure pipeline segments were covered by subpart O of this part and
	(ii) Conduct periodic internal inspections using a high resolution magnetic flux tool on the frequency determined under paragraph (d)(10)(i) of this section, or
	(iii) Use direct assessment (per §192.925, §192.927 and/or §192.929) or pressure testing (per subpart J of this part) for periodic assessment of a portion of a segment to the extent permitted for a baseline assessment under paragraph (d)(9)(iii) of this section.
(11) Making repairs	(i) Perform the following when evaluating an anomaly:
	(A) Use the most conservative calculation for determining remaining strength or an alternative

	validated calculation based on pipe diameter, wall thickness, grade, operating pressure, operating stress level, and operating temperature: and
	(B) Take into account the tolerances of the tools used for the inspection.
	(ii) Repair a defect immediately if any of the following apply:
	(A) The defect is a dent discovered during the baseline assessment for integrity under paragraph (d)(9) of this section and the defect meets the criteria for immediate repair in §192.309(b).
	(B) The defect meets the criteria for immediate repair in §192.933(d).
	(C) The alternative maximum allowable operating pressure was based on a design factor of 0.67 under paragraph (a) of this section and the failure pressure is less than 1.25 times the alternative maximum allowable operating pressure.
	(D) The alternative maximum allowable operating pressure was based on a design factor of 0.56 under paragraph (a) of this section and the failure pressure is less than or equal to 1.4 times the alternative maximum allowable operating pressure.
	(iii) If paragraph (d)(11)(ii) of this section does not require immediate repair, repair a defect within one year if any of the following apply:
	(A) The defect meets the criteria for repair within one year in §192.933(d).
	(B) The alternative maximum allowable operating pressure was based on a design factor of 0.80 under paragraph (a) of this section and the failure pressure is less than 1.25 times the alternative maximum allowable operating pressure.
	(C) The alternative maximum allowable operating pressure was based on a design factor of 0.67 under paragraph (a) of this section and the failure pressure is less than 1.50 times the alternative maximum allowable operating pressure.
	(D) The alternative maximum allowable operating pressure was based on a design factor of 0.56 under paragraph (a) of this section and the failure pressure is less than or equal to 1.80 times the alternative maximum allowable operating pressure.
	(iv) Evaluate any defect not required to be repaired under paragraph (d)(11)(ii) or (iii) of this section to determine its growth rate, set the maximum interval for repair or re-inspection, and repair or re-inspect within that interval.

(e) *Is there any change in overpressure protection associated with operating at the alternative maximum allowable operating pressure?* Notwithstanding the required capacity of pressure relieving and limiting stations otherwise required by §192.201, if an operator establishes a maximum allowable operating pressure for a pipeline segment in accordance with paragraph (a) of this section, an operator must:

(1) Provide overpressure protection that limits mainline pressure to a maximum of 104 percent of the maximum allowable operating pressure; and

(2) Develop and follow a procedure for establishing and maintaining accurate set points for the supervisory control and data acquisition system.

[73 FR 62177, Oct. 17, 2008, as amended by Amdt. 192–111, 74 FR 62505, Nov. 30, 2009]

§192.705 Transmission lines: Patrolling.

(a) Each operator shall have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation.

(b) The frequency of patrols is determined by the size of the line, the operating pressures, the class location, terrain, weather, and other relevant factors, but intervals between patrols may not be longer than prescribed in the following table:

	Maximum interval between patrols	
Class location of line	At highway and railroad crossings	At all other places
1, 2............................	7-1/2 months; but at least twice each calendar year.	15 months; but at least once each calendar year.
3...............................	4-1/2 months; but at least four times each calendar year.	7-1/2 months; but at least twice each calendar year.
4..............................	4-1/2 months; but at least four times each calendar year.	4-1/2 months; but at least four times each calendar year.

(c) Methods of patrolling include walking, driving, flying or other appropriate means of traversing the right-of-way.

[Amdt. 192-21, 40 FR 20283, May 9, 1975, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-78, 61 FR 28786, June 6, 1996]

§192.706 Transmission lines: Leakage surveys.

Leakage surveys of a transmission line must be conducted at intervals not exceeding 15 months, but at least once each calendar year. However, in the case of a transmission line which transports gas in conformity with Sec. 192.625 without an odor or odorant, leakage surveys using leak detector equipment must be conducted--

(a) In Class 3 locations, at intervals not exceeding 7-1/2 months, but at least twice each calendar year; and

(b) In Class 4 locations, at intervals not exceeding 4-1/2 months, but at least four times each calendar year.

[Amdt. 192-21, 40 FR 20283, May 9, 1975, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-71, 59 FR 6585, Feb. 11, 1994]

§192.709 Transmission lines: Record keeping.

Each operator shall maintain the following records for transmission lines for the periods specified:

(a) The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipe remains in service.

(b) The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 5 years. However, repairs generated by patrols, surveys, inspections, or tests required by subparts L and M of this part must be retained in accordance with paragraph (c) of this section.

(c) A record of each patrol, survey, inspection, and test required by subparts L and M of this part must be retained for at least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.

[Amdt. 192-78, 61 FR 28786, June 6, 1996]

§ 192.711 Transmission lines: General requirements for repair procedures.

(a) *Temporary repairs.* Each operator must take immediate temporary measures to protect the public whenever:

(1) A leak, imperfection, or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above 40 percent of the SMYS; and

(2) It is not feasible to make a permanent repair at the time of discovery.

(b) *Permanent repairs.* An operator must make permanent repairs on its pipeline system according to the following:

(1) Non integrity management repairs: The operator must make permanent repairs as soon as feasible.

(2) Integrity management repairs: When an operator discovers a condition on a pipeline covered under Subpart O–Gas Transmission Pipeline Integrity Management, the operator must remediate the condition as prescribed by §192.933(d).

(c) *Welded patch.* Except as provided in §192.717(b)(3), no operator may use a welded patch as a means of repair.

[Amdt. 192–114, 75 FR 48604, Aug. 11, 2010]

§192.717 Transmission lines: Permanent field repair of leaks.

Each permanent field repair of a leak on a transmission line must be made by--

(a) Removing the leak by cutting out and replacing a cylindrical piece of pipe; or

(b) Repairing the leak by one of the following methods:

(1) 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 percent of SMYS.

(2) If the leak is due to a corrosion pit, install a properly designed bolt-on-leak clamp.

(3) If the leak is due to a corrosion pit and on pipe of not more than 40,000 psi (267 Mpa) 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.

(4) 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.

(5) Apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

[Amdt. 192-88, 64 FR 69665, Dec. 14, 1999]

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-11, 37 FR 21816, Oct. 14, 1972; Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-88, 64 FR 69660, Dec. 14, 1999]

§192.719 Transmission lines: Testing of repairs.

(a) Testing of replacement pipe. 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.

(b) Testing of repairs made by welding. Each repair made by welding in accordance with Sec. Sec. 192.713, 192.715, and 192.717 must be examined in accordance with Sec. 192.241.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-54, 51 FR 41635, Nov. 18, 1986

§192.745 Valve maintenance: Transmission lines.

(a) Each transmission line valve that might be required during any emergency must be inspected and partially operated at intervals not exceeding 15 months, but at least once each calendar year.

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

[Amdt. 192-43, 47 FR 46851, Oct. 21, 1982, as amended by Amdt. 192-93, 68 FR 53901, Sept. 15, 2003]

§ 192.933 What actions must be taken to address integrity issues?

(a) *General requirements* . An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment.

(1) *Temporary pressure reduction* . If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must determine any temporary reduction in operating pressure required by this section using ASME/ANSI B31G (incorporated by reference, *see* §192.7) or AGA Pipeline Research Committee Project PR–3–805 ("RSTRENG," incorporated by reference, *see* §192.7) or reduce the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. (See appendix A to this part for information on availability of incorporation by reference information.) An operator must notify PHMSA in accordance with §192.949 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through temporary reduction in operating pressure or other action. An operator must also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(2) *Long-term pressure reduction* . When a pressure reduction exceeds 365 days, the operator must notify PHMSA under §192.949 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline. The operator also must notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(b) *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. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. 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 the 180-day period is impracticable.

(c) *Schedule for evaluation and remediation* . An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.

(d) *Special requirements for scheduling remediation* —(1) *Immediate repair conditions.* An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

(i) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in appendix A to part 192.

(ii) A dent that has any indication of metal loss, cracking or a stress riser.

(iii) An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

(2) *One-year conditions.* Except for conditions listed in paragraph (d)(1) and (d)(3) of this section, an operator must remediate any of the following within one year of discovery of the condition:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper2/3of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

(ii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal seam weld.

(3) *Monitored conditions.* An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:

(i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom1/3of the pipe).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper2/3of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18233, Apr. 6, 2004; Amdt. 192–104, 72 FR 39016, July 17, 2007]

4.T COMPRESSOR STATIONS

T. COMPRESSOR STATIONS (This section does not apply as Ohio Rural Natural Gas Co-Op has no compressor stations)

Compressor stations can take on a broad variety of operational and maintenance issues depending on the size and location. These procedures are set up in a manner in which the general procedures that apply to all compressor stations are up front in sub-sections A. General, and B. Compressor Station Maintenance. If any specific procedures are included in this manual they are contained in sub-sections: C. Operating Procedures for Gas Compressor Units, D. Isolating Main Compressor Units and Yard Piping, and E. Start Up of Liquid Separation Facilities.

Manufacturer operation and maintenance manuals and the specifications and recommendations contained therein can and should be an important part of your O&M program. They will be kept on hand in the appropriate locations by the appropriate people and followed as needed.

A. General

1. Design and Construction

a. Location - Each main compressor building of a compressor station must be located on property which is under control of the operator and must be far enough away from any adjacent property, not under control of the operator, to minimize the possibility of fire being passed to the compressor building from structures on adjacent property. There must be sufficient open space around the main compressor building to allow fire-fighting equipment to move freely.

b. Construction - Each building on a compressor station site must be made of noncombustible materials if it contains either pipe more than 2" in diameter that is carrying gas under pressure or gas handling equipment other than gas utilization equipment used for domestic purposes.

c. Exits - Each operating floor of a main compressor building must have at least two separated and unobstructed exists located to provide a convenient possibility of escape and an unobstructed passage to a place of safety. Each door latch on an exit must be a type which can be readily opened from the inside without a key. Each swinging door located in an exterior wall must be mounted to swing outward.

d. Fences - Each fence around a compressor station must have at least two gates located so as to provide a convenient opportunity for escape to a place of safety, or have other facilities affording a similarly convenient exit from the area. Each gate located within 200 feet of any compressor plant building must open outward and, when occupied, must be able to be opened from the inside without a key.

e. Electrical Facilities - Electrical equipment and wiring installed in compressor stations must conform to the National Electrical Code, ANSI/NFPA 70, as far as that code is applicable.

2. Liquid Removal

   a. Where entrained vapors in gas may liquefy under the anticipated pressure and temperature conditions, the compressor must be protected against the introduction of those liquids in quantities that could cause damage.

   b. Each liquid separator used to remove entrained liquids at a compressor station must have:
      1. Manually operable means of removing these liquids.
      2. Where slugs of liquids could be carried into the compressors, have either automatic liquid removal facilities, an automatic compressor shut down device, or a high liquid level alarm.
      3. Be manufactured in accordance with section VIII of the ASME Boiler and Pressure Vessel Code. (Effective 10/1/15, components must be tested as specified in Section 4.L.9 of this manual). Liquid separators constructed of pipe and fittings without internal welding must be fabricated with a design factor of 0.4 or less.

3. Emergency Shutdown

   a. Except for unattended field compressor stations of 1,000 horsepower or less, each compressor station must have an emergency shutdown system that meets the following:
      1. It must be able to block gas out of the station and blow down the station piping.
      2. It must discharge gas from the blowdown piping at a location where the gas will not create a hazard.
      3. It must provide means for the shutdown of gas compressing equipment, gas fires, and electrical facilities in the vicinity of gas headers and in the compressor building, except, that:
         (i) Electrical circuits that supply emergency lighting required to assist station personnel in evacuating the compressor building and the area in the vicinity of the has headers must remain energized; and
         (ii) Electrical circuits needed to protect equipment from damage may remain energized.
      4. It must be operable from at least two locations, each of which is:
         (i) Outside the gas area of the station
         (ii) Near the exit gates, if the station is fenced, or near emergency exits, if not fenced; and,
         (iii) Not more than 500' from the limits of the station.

   b. If a compressor station supplies gas directly to a distribution system with no other adequate source of gas available, the emergency shutdown system must be designed so that it will not function at the wrong time and cause an unintended outage on the distribution system.

4. Pressure Limiting Devices

Each compressor station must have pressure relief or other suitable protective devices of sufficient capacity and sensitivity to ensure that the maximum allowable operating pressure of the station piping and equipment is not exceeded by more than 10%.

Each vent line that exhausts gas from the pressure relief valves of a compressor station must extend to a location where the gas may be discharged without hazard.

5. Additional Safety Equipment

a. Each compressor station must have adequate fire protection facilities. If fire pumps are part of these facilities, their operation may not be affected by the emergency shutdown system.

b. Each compressor station prime mover, other than an electrical induction or synchronous motor, must have an automatic device to shut down the unit before the speed of either the prime mover or the driven unit exceeds a maximum safe speed.

c. Each compressor unit in a compressor station must have a shutdown or alarm device that operates in the event of inadequate cooling or lubrication of the unit.

d. Each compressor station gas engine that operates with pressure gas injection must be equipped so that stoppage of the engine automatically shuts off the fuel and vents the engine distribution manifold.

e. Each muffler for a gas engine in a compressor station must have vent slots or holes in the baffles of each compartment to prevent gas from being trapped in the muffler.

6. Ventilation

Each compressor station building must be ventilated to ensure that employees are not endangered by the accumulation of gas in rooms, sumps, attics, pits or other enclosed places.

B. Compressor Station Maintenance

1. Inspection and Testing of Pressure Limiting Devices

Expect for rupture discs, each pressure relieving device in a compressor station must be inspected and tested in accordance with § 192.73 9 and § 192.743, and must be operated periodically to determine that it opens at the correct set pressure.

Any defective or inadequate equipment which is found must be promptly repaired or replaced.

Each remote control shutdown device must be inspected and tested at intervals once each calendar year, not to exceed 15 months, to determine that it functions properly.

2. Storage of Combustible Materials

Flammable or combustible materials in quantities beyond those required for everyday use, or other than those normally used in the compressor buildings, must be stored a safe distance from the compressor buildings.

If above ground oil or gasoline storage tanks are present, they must be protected in accordance with National Fire Protection Association Standard No. 30.

3. Gas Detection

Each compressor building in a compressor station must have a fixed gas detection and alarm system, unless the building is constructed so that at least 50 percent of its upright side area is permanently open or is located un an unattended field compressor station of 1,000 horsepower or less.

Except when shut down of the system is necessary for maintenance each gas detection and alarm system required by this section must be continuously monitored for a concentration of gas in air of not more than 25 percent of the lower explosive limit and if that concentration of gas is detected, warn persons about to enter the building and persons inside the building of the danger.

Each gas detection and alarm system required by this section must be maintained to function properly. The maintenance must include performance tests.

C. Operating Procedure for Compressor Units

1. Starting and Operating

2. Manual Shutdown Procedure

3. Normal Operation

Facility flow data and pressure data shall be monitored and logged

D. Isolating Compressor Units and Yard Piping

Major Compressor Cylinder Maintenance

1. Valves without operations - The main unit suction, discharge, pressurizing, blowdown recovery valves, and any blowdown valves that vent into a header system will, if possible, be locked in the closed position. The handles will be removed from all valves that cannot be securely locked and the valves will be tagged.

2. All valves will remain deactivated until the work is complete.

3. When any compressor is opened for maintenance, repair or inspection, the work area should be well ventilated.

4. A blind flange would be installed in each flange connection on the suction and discharge lines.

5. The piping will be purged and filled with an inert gas. A CGl will be used to determine if a hazardous mixture is present in the piping or in the surrounding area.

Minor Compressor Cylinder Maintenance

1. Minor compressor cylinder maintenance is any work which can be accomplished in a short period of time that does not require the use of tools or methods which could not produce an unsafe condition, utilizing the following procedure. Examples of minor maintenance are replacing valves~ changing valve gaskets, replacing unloader valve stem packing, etc. The same procedure will be used for minor maintenance as for major maintenance with the exception that step 4 and 5 are omitted.

Station Piping

1. Close station sidegate valves.

2. Deactivate the sidegate valve operators by closing off the gas supply valve, venting the gas from the motor, and breaking apart the union between the supply valve and motor. Place a handwheel on each sidegate valve to insure total closure prior to blowdown.

3. Close and lock all other valves where a source of gas could enter the system.

4. Blowdown yard piping.

5. Position other valves within the station to obtain the most positive isolation of the work area.

6. Properly purge all lines with gas before placing back in service.

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§192.163 Compressor stations: Design and construction.

(a) *Location of compressor building.* Except for a compressor building on a platform located offshore or in inland navigable waters, each main compressor building of a compressor station must be located on property under the control of the operator. It must be far enough away from adjacent property, not under control of the operator, to minimize the possibility of fire being communicated to the compressor building from structures on adjacent property. There must be enough open space around the main compressor building to allow the free movement of fire-fighting equipment.

(b) *Building construction.* Each building on a compressor station site must be made of noncombustible materials if it contains either—

(1) Pipe more than 2 inches (51 millimeters) in diameter that is carrying gas under pressure; or

(2) Gas handling equipment other than gas utilization equipment used for domestic purposes.

(c) *Exits.* Each operating floor of a main compressor building must have at least two separated and unobstructed exits located so as to provide a convenient possibility of escape and an unobstructed passage to a place of safety. Each door latch on an exit must be of a type which can be readily opened from the inside without a key. Each swinging door located in an exterior wall must be mounted to swing outward.

(d) *Fenced areas.* Each fence around a compressor station must have at least two gates located so as to provide a convenient opportunity for escape to a place of safety, or have other facilities affording a similarly convenient exit from the area. Each gate located within 200 feet (61 meters) of any compressor plant building must open outward and, when occupied, must be openable from the inside without a key.

(e) *Electrical facilities.* Electrical equipment and wiring installed in compressor stations must conform to the NFPA-70, so far as that code is applicable.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976; Amdt. 192-37, 46 FR 10159, Feb. 2, 1981; 58 FR 14521, Mar. 18, 1993; Amdt. 192-85, 63 FR 37502, 37503, July 13, 1998; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§192.165 Compressor stations: Liquid removal.

Link to an amendment published at 80 FR 12778, March 11, 2015.

(a) Where entrained vapors in gas may liquefy under the anticipated pressure and temperature conditions, the compressor must be protected against the introduction of those liquids in quantities that could cause damage.

(b) Each liquid separator used to remove entrained liquids at a compressor station must:

(1) Have a manually operable means of removing these liquids.

(2) Where slugs of liquid could be carried into the compressors, have either automatic liquid removal facilities, an automatic compressor shutdown device, or a high liquid level alarm; and

(3) Be manufactured in accordance with section VIII of the ASME Boiler and Pressure Vessel Code (BPVC) (incorporated by reference, *see* §192.7), except that liquid separators constructed of pipe and fittings without internal welding must be fabricated with a design factor of 0.4, or less.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§192.167 Compressor stations:
Emergency shutdown.

(a) Except for unattended field compressor stations of 1,000 horsepower (746 kilowatts) or less, each compressor station must have an emergency shutdown system that meets the following:

(1) It must be able to block gas out of the station and blow down the station piping.

(2) It must discharge gas from the blowdown piping at a location where the gas will not create a hazard.

(3) It must provide means for the shutdown of gas compressing equipment, gas fires, and electrical facilities in the vicinity of gas headers and in the compressor building, except that:

(i) Electrical circuits that supply emergency lighting required to assist station personnel in evacuating the compressor building and the area in the vicinity of the gas headers must remain energized; and

(ii) Electrical circuits needed to protect equipment from damage may remain energized.

(4) It must be operable from at least two locations, each of which is:

(i) Outside the gas area of the station;

(ii) Near the exit gates, if the station is fenced, or near emergency exits, if not fenced; and

(iii) Not more than 500 feet (153 meters) from the limits of the station.

(b) If a compressor station supplies gas directly to a distribution system with no other adequate source of gas available, the emergency shutdown system must be designed so that it will not function at the wrong time and cause an unintended outage on the distribution system.

(c) On a platform located offshore or in inland navigable waters, the emergency shutdown system must be designed and installed to actuate automatically by each of the following events:

(1) In the case of an unattended compressor station:

(i) When the gas pressure equals the maximum allowable operating pressure plus 15 percent; or

(ii) When an uncontrolled fire occurs on the platform; and

(2) In the case of a compressor station in a building:

(i) When an uncontrolled fire occurs in the building; or

(ii) When the concentration of gas in air reaches 50 percent or more of the lower explosive limit in a building which has a source of ignition.

For the purpose of paragraph (c)(2)(ii) of this section, an electrical facility which conforms to Class 1, Group D, of the National Electrical Code is not a source of ignition.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§192.169 Compressor stations: Pressure limiting devices.

(a) Each compressor station must have pressure relief or other suitable protective devices of sufficient capacity and sensitivity to ensure that the maximum allowable operating pressure of the station piping and equipment is not exceeded by more than 10 percent.

(b) Each vent line that exhausts gas from the pressure relief valves of a compressor station must extend to a location where the gas may be discharged without hazard.

§192.171 Compressor stations: Additional safety equipment.

(a) Each compressor station must have adequate fire protection facilities. If fire pumps are a part of these facilities, their operation may not be affected by the emergency shutdown system.

(b) Each compressor station prime mover, other than an electrical induction or synchronous motor, must have an automatic device to shut down the unit before the speed of either theprime mover or the driven unit exceeds a maximum safe speed.

(c) Each compressor unit in a compressor station must have a shutdown or alarm device that operates in the event of inadequate cooling or lubrication of the unit.

(d) Each compressor station gas engine that operates with pressure gas injection must be equipped so that stoppage of the engine automatically shuts off the fuel and vents the engine distribution manifold.

(e) Each muffler for a gas engine in a compressor station must have vent slots or holes in the baffles of each compartment to prevent gas from being trapped in the muffler.

§192.173 Compressor stations: Ventilation.

Each compressor station building must be ventilated to ensure that employees are not endangered by the accumulation of gas in rooms, sumps, attics, pits, or other enclosed places.

§192.731 Compressor stations: Inspection and testing of relief devices.

(a) Except for rupture discs, each pressure relieving device in a compressor station must be inspected and tested in accordance with Sec. Sec. 192.739 and 192.743, and must be operated periodically to determine that it opens at the correct set pressure.

(b) Any defective or inadequate equipment found must be promptly repaired or replaced.

(c) Each remote control shutdown device must be inspected and tested at intervals not exceeding 15 months, but at least once each calendar year, to determine that it functions properly.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982]

§192.733 [Removed]

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-71, 59 FR 6575, Feb. 11, 1994]

§192.735 Compressor stations: Storage of combustible materials.

(a) Flammable or combustible materials in quantities beyond those required for everyday use, or other than those normally used in compressor buildings, must be stored a safe distance from the compressor building.

(b) Aboveground oil or gasoline storage tanks must be protected in accordance with NFPA-30 (incorporated by reference, see §192.7).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§192.736 Compressor stations: Gas detection.

(a) Not later than September 16, 1996, each compressor building in a compressor station must have a fixed gas detection and alarm system, unless the building is--

(1) Constructed so that at least 50 percent of its upright side area is permanently open; or

(2) Located in an unattended field compressor station of 1,000 horsepower (746 kW) or less.

(b) Except when shutdown of the system is necessary for maintenance under paragraph (c) of this section, each gas detection and alarm system required by this section must--

(1) Continuously monitor the compressor building for a concentration of gas in air of not more than 25 percent of the lower explosive limit; and

(2) If that concentration of gas is detected, warn persons about to enter the building and persons inside the building of the danger.

(c) Each gas detection and alarm system required by this section must be maintained to function properly. The maintenance must include performance tests.

[58 FR 48464, Sept. 16, 1993, as amended by Amdt. 192-85, 63 FR 37504, July 13, 1998]

5. INTEGRITY MANAGEMENT

5. INTEGRITY MANAGEMENT PLAN

Pipeline integrity management is a process for assessing and mitigating pipeline risks in an effort to reduce both the likelihood and consequences of incidents. The Pipeline Safety Improvement Act of 2002 is a federally mandated legislation that addressed risk analysis and integrity management programs for pipeline operators. It also directed the U.S. Department of Transportation (DOT) to adopt regulations relating to integrity management. DOT finalized these regulations in December 17, 2004.

Pipeline integrity management is a systematic and comprehensive process designed to provide information to effectively allocate resources for the appropriate prevention, detection and mitigation activities. The program builds on the existing foundation of pipeline safety regulations covering design, construction, testing, operation and maintenance that has been in place for many years.

Natural gas transmission pipeline operators were required to begin conducting assessment by June 17, 2004, have a management program in place by December 17, 2004, and to complete baseline assessments of pipe in high consequence areas by 2012.

Natural gas distribution operators, master meter operators and small LPG operators are required to develop and implement an integrity management plan by August 2, 2011. Program requirements for master meter operators and small LPG operators are simpler than those for natural gas distribution operators.

Installation of EFV's in new and replacement services was required to begin by February 2, 2010.

Ohio Rural Natural Gas Co-Op is planning or has implemented an integrity management program for their pipelines according to the DOT regulations.

Ohio Rural Natural Gas Co-Op 's Integrity Management Program is contained in a separate manual.

Subpart O—Gas Transmission Pipeline Integrity Management

Source: 68 FR 69817, Dec. 15, 2003, unless otherwise noted.

§ 192.901 What do the regulations in this subpart cover?

This subpart prescribes minimum requirements for an integrity management program on any gas transmission pipeline covered under this part. For gas transmission pipelines constructed of plastic, only the requirements in §§192.917, 192.921, 192.935 and 192.937 apply.

§192.903 What definitions apply to this subpart?

The following definitions apply to this subpart:

Assessment is the use of testing techniques as allowed in this subpart to ascertain the condition of a covered pipeline segment.

Confirmatory direct assessment is an integrity assessment method using more focused application of the principles and techniques of direct assessment to identify internal and external corrosion in a covered transmission pipeline segment.

Covered segment or covered pipeline segment means a segment of gas transmission pipeline located in a high consequence area. The terms gas and transmission line are defined in §192.3.

Direct assessment is an 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.

High consequence area means an area established by one of the methods described in paragraphs (1) or (2) as follows:

(1) An area defined as—

(i) A Class 3 location under §192.5; or

(ii) A Class 4 location under §192.5; or

(iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or

(iv) Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site.

(2) The area within a potential impact circle containing—

(i) 20 or more buildings intended for human occupancy, unless the exception in paragraph (4) applies; or

(ii) An identified site.

(3) Where a potential impact circle is calculated under either method (1) or (2) 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.)

(4) If in identifying a high consequence area under paragraph (1)(iii) of this definition or paragraph (2)(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).

Identified site means 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.

Potential impact circle is a circle of radius equal to the potential impact radius (PIR).

Potential impact radius (PIR) means 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.

NOTE: 0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas must use section 3.2 of ASME/ANSI B31.8S (incorporated by reference, *see*§192.7) to calculate the impact radius formula.

Remediation is 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.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18231, Apr. 6, 2004; Amdt. 192-95, 69 FR 29904, May 26, 2004; Amdt. 192-103, 72 FR 4657, Feb. 1, 2007; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§ 192.905 How does an operator identify a high consequence area?

(a) *General.* To determine which segments of an operator's transmission pipeline system are covered by this subpart, an operator must identify the high consequence areas. An operator must use method (1) or (2) from the definition in §192.903 to identify a high consequence area. An operator may apply one method to its entire pipeline system, or an operator may 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. (*See* appendix E.I. for guidance on identifying high consequence areas.)

(b)(1) *Identified sites.* An operator must identify an identified site, for purposes of this subpart, 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.

(2) 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 (*e.g.,* a sign); or

(ii) The site is licensed or registered by a Federal, State, or local government agency; or

(iii) The site is on a list (including a list on an internet web site) or map maintained by or available from a Federal, State, or local government agency and available to the general public.

(c) *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 §192.903, the operator must complete the evaluation using method (1) or (2). 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.

§ 192.907 What must an operator do to implement this subpart?

(a) *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 §192.911 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.

(b) *Implementation Standards.* In carrying out this subpart, an operator must follow the requirements of this subpart and of ASME/ANSI B31.8S (incorporated by reference, *see* §192.7) 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 an equivalent level of safety to the public and property. In the event of a conflict between this subpart and ASME/ANSI B31.8S, the requirements in this subpart control.

§ 192.909 How can an operator change its integrity management program?

(a) *General.* An operator must document any change to its program and the reasons for the change before implementing the change.

(b) *Notification.* An operator must notify OPS, in accordance with §192.949, of any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State. An operator must provide the notification within 30 days after adopting this type of change into its program.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18231, Apr. 6, 2004]

§ 192.911 What are the elements of an integrity management program?

An operator's initial integrity management program begins with a framework (*see* §192.907) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S (incorporated by reference, *see* §192.7) for more detailed information on the listed element.)

(a) An identification of all high consequence areas, in accordance with §192.905.

(b) A baseline assessment plan meeting the requirements of §192.919 and §192.921.

(c) An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (§192.917) and to evaluate the merits of additional preventive and mitigative measures (§192.935) for each covered segment.

(d) A direct assessment plan, if applicable, meeting the requirements of §192.923, and depending on the threat assessed, of §§192.925, 192.927, or 192.929.

(e) Provisions meeting the requirements of §192.933 for remediating conditions found during an integrity assessment.

(f) A process for continual evaluation and assessment meeting the requirements of §192.937.

(g) If applicable, a plan for confirmatory direct assessment meeting the requirements of §192.931.

(h) Provisions meeting the requirements of §192.935 for adding preventive and mitigative measures to protect the high consequence area.

(i) A performance plan as outlined in ASME/ANSI B31.8S, section 9 that includes performance measures meeting the requirements of §192.945.

(j) Record keeping provisions meeting the requirements of §192.947.

(k) A management of change process as outlined in ASME/ANSI B31.8S, section 11.

(l) A quality assurance process as outlined in ASME/ANSI B31.8S, section 12.

(m) A communication plan that includes the elements of ASME/ANSI B31.8S, section 10, and that includes procedures for addressing safety concerns raised by—

(1) OPS; and

(2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.

(n) Procedures for providing (when requested), by electronic or other means, a copy of the operator's risk analysis or integrity management program to—

(1) OPS; and

(2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.

(o) Procedures for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks.

(p) A process for identification and assessment of newly-identified high consequence areas. (*See* §192.905 and §192.921.)

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18231, Apr. 6, 2004]

§ 192.913 When may an operator deviate its program from certain requirements of this subpart?

(a) *General.* ASME/ANSI B31.8S (incorporated by reference, *see* §192.7) provides the essential features of a performance-based or a prescriptive integrity management program. An operator that uses a performance-based approach that satisfies the requirements for exceptional performance in paragraph (b) of this section may deviate from certain requirements in this subpart, as provided in paragraph (c) of this section.

(b) *Exceptional performance.* An operator must be able to demonstrate the exceptional performance of its integrity management program through the following actions.

(1) To deviate from any of the requirements set forth in paragraph (c) of this section, an operator must have a performance-based integrity management program that meets or exceed the performance-based requirements of ASME/ANSI B31.8S and includes, at a minimum, the following elements—

(i) A comprehensive process for risk analysis;

(ii) All risk factor data used to support the program;

(iii) A comprehensive data integration process;

(iv) A procedure for applying lessons learned from assessment of covered pipeline segments to pipeline segments not covered by this subpart;

(v) A procedure for evaluating every incident, including its cause, within the operator's sector of the pipeline industry for implications both to the operator's pipeline system and to the operator's integrity management program;

(vi) A performance matrix that demonstrates the program has been effective in ensuring the integrity of the covered segments by controlling the identified threats to the covered segments;

(vii) Semi-annual performance measures beyond those required in §192.945 that are part of the operator's performance plan. (*See* §192.911(i).) An operator must submit these measures, by electronic or other means, on a semi-annual frequency to OPS in accordance with §192.951; and

(viii) An analysis that supports the desired integrity reassessment interval and the remediation methods to be used for all covered segments.

(2) In addition to the requirements for the performance-based plan, an operator must—

(i) Have completed at least two integrity assessments on each covered pipeline segment the operator is including under the performance-based approach, and be able to demonstrate that each assessment effectively addressed the identified threats on the covered segment.

(ii) Remediate all anomalies identified in the more recent assessment according to the requirements in §192.933, and incorporate the results and lessons learned from the more recent assessment into the operator's data integration and risk assessment.

(c) *Deviation.* Once an operator has demonstrated that it has satisfied the requirements of paragraph (b) of this section, the operator may deviate from the prescriptive requirements of ASME/ANSI B31.8S and of this subpart only in the following instances.

(1) The time frame for reassessment as provided in §192.939 except that reassessment by some method allowed under this subpart (*e.g.*, confirmatory direct assessment) must be carried out at intervals no longer than seven years;

(2) The time frame for remediation as provided in §192.933 if the operator demonstrates the time frame will not jeopardize the safety of the covered segment.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18231, Apr. 6, 2004]

§ 192.915 What knowledge and training must personnel have to carry out an integrity management program?

(a) *Supervisory personnel.* The integrity management program must provide that each supervisor whose responsibilities relate to the integrity management program possesses and maintains a thorough knowledge of the integrity management program and of the elements for which the supervisor is responsible. The program must provide that any person who qualifies as a supervisor for the integrity management program has appropriate training or experience in the area for which the person is responsible.

(b) *Persons who carry out assessments and evaluate assessment results.* The integrity management program must provide criteria for the qualification of any person—

(1) Who conducts an integrity assessment allowed under this subpart; or

(2) Who reviews and analyzes the results from an integrity assessment and evaluation; or

(3) Who makes decisions on actions to be taken based on these assessments.

(c) *Persons responsible for preventive and mitigative measures.* The integrity management program must provide criteria for the qualification of any person—

(1) Who implements preventive and mitigative measures to carry out this subpart, including the marking and locating of buried structures; or

(2) Who directly supervises excavation work carried out in conjunction with an integrity assessment.

§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(a) *Threat identification.* An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 2, which are grouped under the following four categories:

(1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

(2) Static or resident threats, such as fabrication or construction defects;

(3) Time independent threats such as third party damage and outside force damage; and

(4) Human error.

(b) *Data gathering and integration.* To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.

(c) *Risk assessment.* An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§§192.919, 192.921, 192.937), and to determine what additional preventive and mitigative measures are needed (§192.935) for the covered segment.

(d) *Plastic transmission pipeline.* An operator of a plastic transmission pipeline must assess the threats to each covered segment using the information in sections 4 and 5 of ASME B31.8S, and consider any threats unique to the integrity of plastic pipe.

(e) *Actions to address particular threats.* If an operator identifies any of the following threats, the operator must take the following actions to address the threat.

(1) *Third party damage.* An operator must utilize the data integration required in paragraph (b) of this section and ASME/ANSI B31.8S, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with §192.935 and monitor the effectiveness of the preventive measures. If, in conducting a baseline assessment under §192.921, or a reassessment under §192.937, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage may exist in the covered segment.

An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration.

(2) *Cyclic fatigue.* An operator must evaluate whether cyclic fatigue or other loading condition (including ground movement, suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, or other defect in the covered segment. An evaluation must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the evaluation together with the criteria used to evaluate the significance of this threat to the covered segment to prioritize the integrity baseline assessment or reassessment.

(3) *Manufacturing and construction defects.* If an operator identifies the threat of manufacturing and construction defects (including seam defects) in the covered segment, an operator must analyze the covered segment to determine the risk of failure from these defects. The analysis must consider the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects if the operating pressure on the covered segment has not increased over the maximum operating pressure experienced during the five years preceding identification of the high consequence area. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

(i) Operating pressure increases above the maximum operating pressure experienced during the preceding five years;

(ii) MAOP increases; or

(iii) The stresses leading to cyclic fatigue increase.

(4) *ERW pipe.* If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW), lap welded pipe or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or noncovered segment in the pipeline system with such pipe has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

(5) *Corrosion.* If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in §192.933), the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's established operating and maintenance procedures under part 192 for testing and repair.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18231, Apr. 6, 2004]

§ 192.919 What must be in the baseline assessment plan?

An operator must include each of the following elements in its written baseline assessment plan:

(a) Identification of the potential threats to each covered pipeline segment and the information supporting the threat identification. (*See* §192.917.);

(b) The methods selected to assess the integrity of the line pipe, including an explanation of why the assessment method was selected to address the identified threats to each covered segment. The integrity assessment method an operator uses must be based on the threats identified to the covered segment. (*See* §192.917.) More than one method may be required to address all the threats to the covered pipeline segment;

(c) A schedule for completing the integrity assessment of all covered segments, including risk factors considered in establishing the assessment schedule;

(d) If applicable, a direct assessment plan that meets the requirements of §§192.923, and depending on the threat to be addressed, of §192.925, §192.927, or §192.929; and

(e) A procedure to ensure that the baseline assessment is being conducted in a manner that minimizes environmental and safety risks.

§ 192.921 How is the baseline assessment to be conducted?

(a) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods depending on the threats to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (*See* §192.917).

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

(2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with §192.939.

(3) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with, as applicable, the requirements specified in §§192.925, 192.927 or 192.929;

(4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with §192.949. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(b) *Prioritizing segments.* An operator must prioritize the covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats to each covered segment. The risk analysis must comply with the requirements in §192.917.

(c) *Assessment for particular threats.* In choosing an assessment method for the baseline assessment of each covered segment, an operator must take the actions required in §192.917(e) to address particular threats that it has identified.

(d) *Time period.* An operator must prioritize all the covered segments for assessment in accordance with §192.917 (c) and paragraph (b) of this section. An operator must assess at least 50% of the covered segments beginning with the highest risk segments, by December 17, 2007. An operator must complete the baseline assessment of all covered segments by December 17, 2012.

(e) *Prior assessment.* An operator may use a prior integrity assessment conducted before December 17, 2002 as a baseline assessment for the covered segment, if the integrity assessment meets the baseline requirements in this subpart and subsequent remedial actions to address the conditions listed in §192.933 have been carried out. In addition, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe in the covered segment according to the requirements of §192.937 and §192.939.

(f) *Newly identified areas.* When an operator identifies a new high consequence area (*see* §192.905), an operator must complete the baseline assessment of the line pipe in the newly identified high consequence area within ten (10) years from the date the area is identified.

(g) *Newly installed pipe.* An operator must complete the baseline assessment of a newly-installed segment of pipe covered by this subpart within ten (10) years from the date the pipe is installed. An operator may conduct a pressure test in accordance with paragraph (a)(2) of this section, to satisfy the requirement for a baseline assessment.

(h) *Plastic transmission pipeline.* If the threat analysis required in §192.917(d) on a plastic transmission pipeline indicates that a covered segment is susceptible to failure from causes other than third-party damage, an operator must conduct a baseline assessment of the segment in accordance with the requirements of this section and of §192.917. The operator must justify the use of an alternative assessment method that will address the identified threats to the covered segment.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18232, Apr. 6, 2004]

§192.923 How is direct assessment used and for what threats?

(a) *General.* An operator may use direct assessment either as a primary assessment method or as a supplement to the other assessment methods allowed under this subpart. An operator may only use direct assessment as the primary assessment method to address the identified threats of external corrosion (EC), internal corrosion (IC), and stress corrosion cracking (SCC).

(b) *Primary method.* An operator using direct assessment as a primary assessment method must have a plan that complies with the requirements in—

(1) Section 192.925 and ASME/ANSI B31.8S (incorporated by reference, see §192.7) section 6.4, and NACE SP0502 (incorporated by reference, see §192.7), if addressing external corrosion (EC).

(2) Section 192.927 and ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.4, appendix B2, if addressing internal corrosion (IC).

(3) Section 192.929 and ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), appendix A3, if addressing stress corrosion cracking (SCC).

(c) *Supplemental method.* An operator using direct assessment as a supplemental assessment method for any applicable threat must have a plan that follows the requirements for confirmatory direct assessment in §192.931.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-114, 75 FR 48604, Aug. 11, 2010; Amdt. 192-119, 80 FR 178, 182, Jan. 5, 2015]

§192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?

Link to an amendment published at 80 FR 12779, March 11, 2015.

(a) *Definition.* ECDA is a four-step process that combines preassessment, indirect inspection, direct examination, and post assessment to evaluate the threat of external corrosion to the integrity of a pipeline.

(b) *General requirements.* An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.4, and in NACE SP0502 (incorporated by reference, *see* §192.7). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (§192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by §192.917(e)(1).

(1) *Preassessment.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502, section 3, the plan's procedures for preassessment must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment; and

(ii) The basis on which an operator selects at least two different, but complementary indirect assessment tools to assess each ECDA Region. If an operator utilizes an indirect inspection method that is not discussed in Appendix A of NACE SP0502, the operator must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.

(2) *Indirect examination.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502, section 4, the plan's procedures for indirect examination of the ECDA regions must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;

(ii) Criteria for identifying and documenting those indications that must be considered for excavation and direct examination. Minimum identification criteria include the known sensitivities of assessment tools, the procedures for using each tool, and the approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected;

(iii) Criteria for defining the urgency of excavation and direct examination of each indication identified during the indirect examination. These criteria must specify how an operator will define the urgency of excavating the indication as immediate, scheduled or monitored; and

(iv) Criteria for scheduling excavation of indications for each urgency level.

(3) *Direct examination.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502, section 5, the plan's procedures for direct examination of indications from the indirect examination must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;

(ii) Criteria for deciding what action should be taken if either:

(A) Corrosion defects are discovered that exceed allowable limits (Section 5.5.2.2 of NACE SP0502), or

(B) Root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE SP0502);

(iii) Criteria and notification procedures for any changes in the ECDA Plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications; and

(iv) Criteria that describe how and on what basis an operator will reclassify and reprioritize any of the provisions that are specified in section 5.9 of NACE SP0502.

(4) *Post assessment and continuing evaluation.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502, section 6, the plan's procedures for post assessment of the effectiveness of the ECDA process must include—

(i) Measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion in covered segments; and

(ii) Criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the covered segment at an interval less than that specified in §192.939. (See Appendix D of NACE SP0502.)

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 29904, May 26, 2004; Amdt. 192-114, 75 FR 48604, Aug. 11, 2010; Amdt. 192-119, 80 FR 178, Jan. 5, 2015]

§ 192.927 What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?

(a) *Definition.* Internal Corrosion Direct Assessment (ICDA) is a process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO_2,O_2,hydrogen sulfide or other contaminants present in the gas.

(b) *General requirements.* An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.4 and appendix B2. The ICDA process described in this section applies only for a segment of pipe transporting nominally dry natural gas, and not for a segment with electrolyte nominally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolyte present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to effectively address internal corrosion, and must provide notification in accordance with §192.921 (a)(4) or §192.937(c)(4).

(c) *The ICDA plan.* An operator must develop and follow an ICDA plan that provides for preassessment, identification of ICDA regions and excavation locations, detailed examination of pipe at excavation locations, and post-assessment evaluation and monitoring.

(1) *Preassessment.* In the preassessment stage, an operator must gather and integrate data and information needed to evaluate the feasibility of ICDA for the covered segment, and to support use of a model to identify the locations along the pipe segment where electrolyte may accumulate, to identify ICDA regions, and to identify areas within the covered segment where liquids may potentially be entrained. This data and information includes, but is not limited to—

(i) All data elements listed in appendix A2 of ASME/ANSI B31.8S;

(ii) Information needed to support use of a model that an operator must use to identify areas along the pipeline where internal corrosion is most likely to occur. (*See* paragraph (a) of this section.) This information, includes, but is not limited to, location of all gas input and withdrawal points on the line; location of all low points on covered segments such as sags, drips, inclines, valves, manifolds, dead-legs, and traps; the elevation profile of the pipeline in sufficient detail that angles of inclination can be calculated for all pipe segments; and the diameter of the pipeline, and the range of expected gas velocities in the pipeline;

(iii) Operating experience data that would indicate historic upsets in gas conditions, locations where these upsets have occurred, and potential damage resulting from these upset conditions; and

(iv) Information on covered segments where cleaning pigs may not have been used or where cleaning pigs may deposit electrolytes.

(2) *ICDA region identification.* An operator's plan must identify where all ICDA Regions are located in the transmission system, in which covered segments are located. An ICDA Region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur and where further evaluation is needed. An ICDA Region may encompass one or more covered segments. In the identification process, an operator must use the model in GRI 02–0057, "Internal Corrosion Direct Assessment of Gas Transmission Pipelines—Methodology," (incorporated by reference, *see* §192.7). An operator may use another model if the operator demonstrates it is equivalent to the one shown in GRI 02–0057. A model must consider changes in pipe diameter, locations where gas enters a line (potential to introduce liquid) and locations down stream of gas draw-offs (where gas velocity is reduced) to define the critical pipe angle of inclination above which water film cannot be transported by the gas.

(3) *Identification of locations for excavation and direct examination.* An operator's plan must identify the locations where internal corrosion is most likely in each ICDA region. In the location identification process, an operator must identify a minimum of two locations for excavation within each ICDA Region within a covered segment and must perform a direct examination for internal corrosion at each location, using ultrasonic thickness measurements, radiography, or other generally accepted measurement technique. One location must be the low point (*e.g.,* sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further downstream, within a covered segment, near the end of the ICDA Region. If corrosion exists at either location, the operator must—

(i) Evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with §192.933;

(ii) As part of the operator's current integrity assessment either perform additional excavations in each covered segment within the ICDA region, or use an alternative assessment method allowed by this subpart to assess the line pipe in each covered segment within the ICDA region for internal corrosion; and

(iii) Evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA region containing the covered segment in which the corrosion was found, and as appropriate, remediate the conditions the operator finds in accordance with §192.933.

(4) *Post-assessment evaluation and monitoring.* An operator's plan must provide for evaluating the effectiveness of the ICDA process and continued monitoring of covered segments where internal corrosion has been identified. The evaluation and monitoring process includes—

(i) Evaluating the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in §192.939. An operator must carry out this evaluation within a year of conducting an ICDA; and

(ii) Continually monitoring each covered segment where internal corrosion has been identified using techniques such as coupons, UT sensors or electronic probes, periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this subpart, and risk factors specific to the covered segment. If an operator finds any evidence of corrosion products in the covered segment, the operator must take prompt action in accordance with one of the two following required actions and remediate the conditions the operator finds in accordance with §192.933.

(A) Conduct excavations of covered segments at locations downstream from where the electrolyte might have entered the pipe; or

(B) Assess the covered segment using another integrity assessment method allowed by this subpart.

(5) *Other requirements.* The ICDA plan must also include—

(i) Criteria an operator will apply in making key decisions (*e.g.,* ICDA feasibility, definition of ICDA Regions, conditions requiring excavation) in implementing each stage of the ICDA process;

(ii) Provisions for applying more restrictive criteria when conducting ICDA for the first time on a covered segment and that become less stringent as the operator gains experience; and

(iii) Provisions that analysis be carried out on the entire pipeline in which covered segments are present, except that application of the remediation criteria of §192.933 may be limited to covered segments.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18232, Apr. 6, 2004]

§ 192.929 What are the requirements for using Direct Assessment for Stress Corrosion Cracking (SCCDA)?

(a) *Definition.* Stress Corrosion Cracking Direct Assessment (SCCDA) is a process to assess a covered pipe segment for the presence of SCC primarily by systematically gathering and analyzing excavation data for pipe having similar operational characteristics and residing in a similar physical environment.

(b) *General requirements.* An operator using direct assessment as an integrity assessment method to address stress corrosion cracking in a covered pipeline segment must have a plan that provides, at minimum, for—

(1) *Data gathering and integration.* An operator's plan must provide for a systematic process to collect and evaluate data for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment. This process must include gathering and evaluating data related to SCC at all sites an operator excavates during the conduct of its pipeline operations where the criteria in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), appendix A3.3 indicate the potential for SCC. This data includes at minimum, the data specified in ASME/ANSI B31.8S, appendix A3.

(2) *Assessment method.* The plan must provide that if conditions for SCC are identified in a covered segment, an operator must assess the covered segment using an integrity assessment method specified in ASME/ANSI B31.8S, appendix A3, and remediate the threat in accordance with ASME/ANSI B31.8S, appendix A3, section A3.4.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18233, Apr. 6, 2004]

§192.931 How may Confirmatory Direct Assessment (CDA) be used?

An operator using the confirmatory direct assessment (CDA) method as allowed in §192.937 must have a plan that meets the requirements of this section and of §§192.925 (ECDA) and §192.927 (ICDA).

(a) *Threats.* An operator may only use CDA on a covered segment to identify damage resulting from external corrosion or internal corrosion.

(b) *External corrosion plan.* An operator's CDA plan for identifying external corrosion must comply with §192.925 with the following exceptions.

(1) The procedures for indirect examination may allow use of only one indirect examination tool suitable for the application.

(2) The procedures for direct examination and remediation must provide that—

(i) All immediate action indications must be excavated for each ECDA region; and

(ii) At least one high risk indication that meets the criteria of scheduled action must be excavated in each ECDA region.

(c) *Internal corrosion plan.* An operator's CDA plan for identifying internal corrosion must comply with §192.927 except that the plan's procedures for identifying locations for excavation may require excavation of only one high risk location in each ICDA region.

(d) *Defects requiring near-term remediation.* If an assessment carried out under paragraph (b) or (c) of this section reveals any defect requiring remediation prior to the next scheduled assessment, the operator must schedule the next assessment in accordance with NACE SP0502 (incorporated by reference, *see* §192.7), section 6.2 and 6.3. If the defect requires immediate remediation, then the operator must reduce pressure consistent with §192.933 until the operator has completed reassessment using one of the assessment techniques allowed in §192.937.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-114, 75 FR 48604, Aug. 11, 2010; Amdt. 192-119, 80 FR 178, Jan. 5, 2015]

§ 192.933 What actions must be taken to address integrity issues?

(a) *General requirements* . An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment.

(1) *Temporary pressure reduction* . If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must determine any temporary reduction in operating pressure required by this section using ASME/ANSI B31G (incorporated by reference, *see* §192.7) or AGA Pipeline Research Committee Project PR–3–805 ("RSTRENG," incorporated by reference, *see* §192.7) or reduce the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. (See appendix A to this part for information on availability of incorporation by reference information.) An operator must notify PHMSA in accordance with §192.949 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through temporary reduction in operating pressure or other action. An operator must also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(2) *Long-term pressure reduction* . When a pressure reduction exceeds 365 days, the operator must notify PHMSA under §192.949 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline. The operator also must notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(b) *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. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. 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 the 180-day period is impracticable.

(c) *Schedule for evaluation and remediation* . An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.

(d) *Special requirements for scheduling remediation* —(1) *Immediate repair conditions.* An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

(i) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in appendix A to part 192.

(ii) A dent that has any indication of metal loss, cracking or a stress riser.

(iii) An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

(2) *One-year conditions.* Except for conditions listed in paragraph (d)(1) and (d)(3) of this section, an operator must remediate any of the following within one year of discovery of the condition:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper2/3of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

(ii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal seam weld.

(3) *Monitored conditions.* An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:

(i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom1/3of the pipe).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper2/3of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18233, Apr. 6, 2004; Amdt. 192–104, 72 FR 39016, July 17, 2007]

§192.935 What additional preventive and mitigative measures must an operator take?

(a) *General requirements.* An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (*See* §192.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.

(b) Third party damage and outside force damage—

(1) *Third party damage.* An operator must enhance its damage prevention program, as required under §192.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures to an existing damage prevention program include, at a minimum—

(i) Using qualified personnel (*see* §192.915) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.

(ii) Collecting in a central database information that is location specific on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under part 191.

(iii) Participating in one-call systems in locations where covered segments are present.

(iv) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE SP0502 (incorporated by reference, *see* §192.7). An operator must excavate, and remediate, in accordance with ANSI/ASME B31.8S and §192.933 any indication of coating holidays or discontinuity warranting direct examination.

(2) *Outside force damage.* If an operator determines that outside force (*e.g.*, earth movement, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include, but are not limited to, increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, and relocating the line.

(c) *Automatic shut-off valves (ASV) or Remote control valves (RCV).* If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors—swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.

(d) *Pipelines operating below 30% SMYS.* An operator of a transmission pipeline operating below 30% SMYS located in a high consequence area must follow the requirements in paragraphs (d)(1) and (d)(2) of this section. An operator of a transmission pipeline operating below 30% SMYS located in a Class 3 or Class 4 area but not in a high consequence area must follow the requirements in paragraphs (d)(1), (d)(2) and (d)(3) of this section.

(1) Apply the requirements in paragraphs (b)(1)(i) and (b)(1)(iii) of this section to the pipeline; and

(2) Either monitor excavations near the pipeline, or conduct patrols as required by §192.705 of the pipeline at bi-monthly intervals. If an operator finds any indication of unreported construction activity, the operator must conduct a follow up investigation to determine if mechanical damage has occurred.

(3) Perform semi-annual leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where electrical surveys are impractical).

(e) *Plastic transmission pipeline.* An operator of a plastic transmission pipeline must apply the requirements in paragraphs (b)(1)(i), (b)(1)(iii) and (b)(1)(iv) of this section to the covered segments of the pipeline.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18233, Apr. 6, 2004; Amdt. 192-95, 69 FR 29904, May 26, 2004; Amdt. 192-114, 75 FR 48604, Aug. 11, 2010; Amdt. 192-119, 80 FR 178, Jan. 5, 2015]

§ 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

(a) *General.* After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in §192.939 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (b) of this section. An operator must reassess a covered segment on which a prior assessment is credited as a baseline under §192.921(e) by no later than December 17, 2009. An operator must reassess a covered segment on which a baseline assessment is conducted during the baseline period specified in §192.921(d) by no later than seven years after the baseline assessment of that covered segment unless the evaluation under paragraph (b) of this section indicates earlier reassessment.

(b) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in §192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in 192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§192.917), and decisions about remediation (§192.933) and additional preventive and mitigative actions (§192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.

(c) *Assessment methods.* In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in the covered segment by any of the following methods as appropriate for the threats to which the covered segment is susceptible (*see* §192.917), or by confirmatory direct assessment under the conditions specified in §192.931.

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

(2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with §192.939.

(3) Direct assessment to address threats of external corrosion, internal corrosion, or stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with as applicable, the requirements specified in §§192.925, 192.927 or 192.929;

(4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with §192.949. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(5) Confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than seven years. An operator using this reassessment method must comply with §192.931.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18234, Apr. 6, 2004]

§192.939 What are the required reassessment intervals?

An operator must comply with the following requirements in establishing the reassessment interval for the operator's covered pipeline segments.

(a) *Pipelines operating at or above 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. If an operator establishes a reassessment interval that is greater than seven years, the operator must, within the seven-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with §192.931. The table that follows this section sets forth the maximum allowed reassessment intervals.

(1) *Pressure test or internal inspection or other equivalent technology.* An operator that uses pressure testing or internal inspection as an assessment method must establish the reassessment interval for a covered pipeline segment by—

(i) Basing the interval on the identified threats for the covered segment (see §192.917) and on the analysis of the results from the last integrity assessment and from the data integration and risk assessment required by §192.917; or

(ii) Using the intervals specified for different stress levels of pipeline (operating at or above 30% SMYS) listed in ASME B31.8S (incorporated by reference, *see* §192.7), section 5, Table 3.

(2) *External Corrosion Direct Assessment.* An operator that uses ECDA that meets the requirements of this subpart must determine the reassessment interval according to the requirements in paragraphs 6.2 and 6.3 of NACE SP0502 (incorporated by reference, *see* §192.7).

(3) *Internal Corrosion or SCC Direct Assessment.* An operator that uses ICDA or SCCDA in accordance with the requirements of this subpart must determine the reassessment interval according to the following method. However, the reassessment interval cannot exceed those specified for direct assessment in ASME/ANSI B31.8S, section 5, Table 3.

(i) Determine the largest defect most likely to remain in the covered segment and the corrosion rate appropriate for the pipe, soil and protection conditions;

(ii) Use the largest remaining defect as the size of the largest defect discovered in the SCC or ICDA segment; and

(iii) Estimate the reassessment interval as half the time required for the largest defect to grow to a critical size.

(b) *Pipelines Operating Below 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating below 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. An operator must establish reassessment by at least one of the following—

(1) Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in paragraph (a)(1) of this section except that the stress level referenced in paragraph (a)(1)(ii) of this section would be adjusted to reflect the lower operating stress level. If an established interval is more than seven years, the operator must conduct by the seventh year of the interval either a confirmatory direct assessment in accordance with §192.931, or a low stress reassessment in accordance with §192.941.

(2) Reassessment by ECDA following the requirements in paragraph (a)(2) of this section.

(3) Reassessment by ICDA or SCCDA following the requirements in paragraph (a)(3) of this section.

(4) Reassessment by confirmatory direct assessment at 7-year intervals in accordance with §192.931, with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this section by year 20 of the interval.

(5) Reassessment by the low stress assessment method at 7-year intervals in accordance with §192.941 with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this section by year 20 of the interval.

(6) The following table sets forth the maximum reassessment intervals. Also refer to Appendix E.II for guidance on Assessment Methods and Assessment Schedule for Transmission Pipelines Operating Below 30% SMYS. In case of conflict between the rule and the guidance in the Appendix, the requirements of the rule control. An operator must comply with the following requirements in establishing a reassessment interval for a covered segment:

MAXIMUM REASSESSMENT INTERVAL

Assessment method	Pipeline operating at or above 50% SMYS	Pipeline operating at or above 30% SMYS, up to 50% SMYS	Pipeline operating below 30% SMYS
Internal Inspection Tool, Pressure Test or Direct Assessment	10 years(*)	15 years(*)	20 years.(**)
Confirmatory Direct Assessment	7 years	7 years	7 years.
Low Stress Reassessment	Not applicable	Not applicable	7 years + ongoing actions

			specified in §192.941.

(*)A Confirmatory direct assessment as described in §192.931 must be conducted by year 7 in a 10-year interval and years 7 and 14 of a 15-year interval.

(**)A low stress reassessment or Confirmatory direct assessment must be conducted by years 7 and 14 of the interval.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18234, Apr. 6, 2004; 192-114, 75 FR 48604, Aug. 11, 2010; Amdt. 192-119, 80 FR 178, 182, Jan. 5, 2015]

§ 192.941 What is a low stress reassessment?

(a) *General.* An operator of a transmission line that operates below 30% SMYS may use the following method to reassess a covered segment in accordance with §192.939. This method of reassessment addresses the threats of external and internal corrosion. The operator must have conducted a baseline assessment of the covered segment in accordance with the requirements of §§192.919 and 192.921.

(b) *External corrosion.* An operator must take one of the following actions to address external corrosion on the low stress covered segment.

(1) *Cathodically protected pipe.* To address the threat of external corrosion on cathodically protected pipe in a covered segment, an operator must perform an electrical survey (*i.e.* indirect examination tool/method) at least every 7 years on the covered segment. An operator must use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for the covered segment. This evaluation must consider, at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(2) *Unprotected pipe or cathodically protected pipe where electrical surveys are impractical.* If an electrical survey is impractical on the covered segment an operator must—

(i) Conduct leakage surveys as required by §192.706 at 4-month intervals; and

(ii) Every 18 months, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(c) *Internal corrosion.* To address the threat of internal corrosion on a covered segment, an operator must—

(1) Conduct a gas analysis for corrosive agents at least once each calendar year;

(2) Conduct periodic testing of fluids removed from the segment. At least once each calendar year test the fluids removed from each storage field that may affect a covered segment; and

(3) At least every seven (7) years, integrate data from the analysis and testing required by paragraphs (c)(1)–(c)(2) with applicable internal corrosion leak records, incident reports, safety-related condition reports, repair records, patrol records, exposed pipe reports, and test records, and define and implement appropriate remediation actions.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18234, Apr. 6, 2004]

§ 192.943 When can an operator deviate from these reassessment intervals?

(a) *Waiver from reassessment interval in limited situations.* In the following limited instances, OPS may allow a waiver from a reassessment interval required by §192.939 if OPS finds a waiver would not be inconsistent with pipeline safety.

(1) *Lack of internal inspection tools.* An operator who uses internal inspection as an assessment method may be able to justify a longer reassessment period for a covered segment if internal inspection tools are not available to assess the line pipe. To justify this, the operator must demonstrate that it cannot obtain the internal inspection tools within the required reassessment period and that the actions the operator is taking in the interim ensure the integrity of the covered segment.

(2) *Maintain product supply.* An operator may be able to justify a longer reassessment period for a covered segment if the operator demonstrates that it cannot maintain local product supply if it conducts the reassessment within the required interval.

(b) *How to apply.* If one of the conditions specified in paragraph (a) (1) or (a) (2) of this section applies, an operator may seek a waiver of the required reassessment interval. An operator must apply for a waiver in accordance with 49 U.S.C. 60118(c), at least 180 days before the end of the required reassessment interval, unless local product supply issues make the period impractical. If local product supply issues make the period impractical, an operator must apply for the waiver as soon as the need for the waiver becomes known.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18234, Apr. 6, 2004]

§ 192.945 What methods must an operator use to measure program effectiveness?

(a) *General.* An operator must include in its integrity management program methods to measure, on a semi-annual basis, whether the program is effective in assessing and evaluating the integrity of each covered pipeline segment and in protecting the high consequence areas. These measures must include the four overall performance measures specified in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 9.4, and the specific measures for each identified threat specified in ASME/ANSI B31.8S, Appendix A. An operator must submit the four overall performance measures, by electronic or other means, on a semi-annual frequency to OPS in accordance with §192.951. An operator must submit its first report on overall performance measures by August 31, 2004. Thereafter, the performance measures must be complete through June 30 and December 31 of each year and must be submitted within 2 months after those dates.

(b) *External Corrosion Direct assessment.* In addition to the general requirements for performance measures in paragraph (a) of this section, an operator using direct assessment to assess the external corrosion threat must define and monitor measures to determine the effectiveness of the ECDA process. These measures must meet the requirements of §192.925.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18234, Apr. 6, 2004]

§ 192.947 What records must an operator keep?

An operator must maintain, for the useful life of the pipeline, records that demonstrate compliance with the requirements of this subpart. At minimum, an operator must maintain the following records for review during an inspection.

(a) A written integrity management program in accordance with §192.907;

(b) Documents supporting the threat identification and risk assessment in accordance with §192.917;

(c) A written baseline assessment plan in accordance with §192.919;

(d) Documents to support any decision, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements;

(e) Documents that demonstrate personnel have the required training, including a description of the training program, in accordance with §192.915;

(f) Schedule required by §192.933 that prioritizes the conditions found during an assessment for evaluation and remediation, including technical justifications for the schedule.

(g) Documents to carry out the requirements in §§192.923 through 192.929 for a direct assessment plan;

(h) Documents to carry out the requirements in §192.931 for confirmatory direct assessment;

(i) Verification that an operator has provided any documentation or notification required by this subpart to be provided to OPS, and when applicable, a State authority with which OPS has an interstate agent agreement, and a State or local pipeline safety authority that regulates a covered pipeline segment within that State.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18234, Apr. 6, 2004]

§ 192.949 How does an operator notify PHMSA?

An operator must provide any notification required by this subpart by—

(a) Sending the notification to the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP–10, 1200 New Jersey Avenue, SE., Washington, DC 20590-0001;

(b) Sending the notification to the Information Resources Manager by facsimile to (202) 366–7128; or

(c) Entering the information directly on the Integrity Management Database (IMDB) Web site at *http://primis.rspa.dot.gov/gasimp/.*

[68 FR 69817, Dec. 15, 2003, as amended at 70 FR 11139, Mar. 8, 2005; Amdt. 192–103, 72 FR 4657, Feb. 1, 2007; 73 FR 16570, Mar. 28, 2008; 74 FR 2894, Jan. 16, 2009]

§ 192.951 Where does an operator file a report?

An operator must send any performance report required by this subpart to the Information Resources Manager—

(a) By mail to the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP–10, 1200 New Jersey Avenue, SE., Washington, DC 20590-0001;

(b) Via facsimile to (202) 366–7128; or

(c) Through the online reporting system provided by OPS for electronic reporting available at the OPS Home Page at *http://ops.dot.gov.*

[68 FR 69817, Dec. 15, 2003, as amended at 70 FR 11139, Mar. 8, 2005 ; Amdt. 192–103, 72 FR 4657, Feb. 1, 2007; 73 FR 16570, Mar. 28, 2008; 74 FR 2894, Jan. 16, 2009]

Subpart P—Gas Distribution Pipeline Integrity Management (IM)

Source: 74 FR 63934, Dec. 4, 2009, unless otherwise noted.

§ 192.1001 What definitions apply to this subpart?

The following definitions apply to this subpart:

Excavation Damage means 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 means 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 or *IM Plan* means a written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with this subpart.

Integrity Management Program or *IM Program* means an overall approach by an operator to ensure the integrity of its gas distribution system.

Small LPG Operator means an operator of a liquefied petroleum gas (LPG) distribution pipeline that serves fewer than 100 customers from a single source.

§ 192.1003 What do the regulations in this subpart cover?

General. This subpart prescribes minimum requirements for an IM program for any gas distribution pipeline covered under this part, including liquefied petroleum gas systems. A gas distribution operator, other than a master meter operator or a small LPG operator, must follow the requirements in §§192.1005–192.1013 of this subpart. A master meter operator or small LPG operator of a gas distribution pipeline must follow the requirements in §192.1015 of this subpart.

§ 192.1005 What must a gas distribution operator (other than a master meter or small LPG operator) do to implement

this subpart?

No later than August 2, 2011 a gas distribution operator must develop and implement an integrity management program that includes a written integrity management plan as specified in §192.1007.

§ 192.1007 What are the required elements of an integrity management plan?

A written integrity management plan must contain procedures for developing and implementing the following elements:

(a) *Knowledge.* An operator must demonstrate an understanding of its gas distribution system developed from reasonably available information.

(1) 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.

(2) Consider the information gained from past design, operations, and maintenance.

(3) Identify additional information needed and provide a plan for gaining that information over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).

(4) Develop and implement a process by which the IM program will be reviewed periodically and refined and improved as needed.

(5) 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.

(b) *Identify threats.* The operator must consider the following categories of threats to each gas distribution pipeline: Corrosion, natural forces, excavation damage, other outside force damage, material, weld or joint failure (including compression coupling), equipment failure, incorrect operation, and other concerns that could threaten the integrity of its pipeline. An operator must consider reasonably available information to identify existing and potential threats. Sources of data may include, but are not limited to, incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.

(c) *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 the 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 (e.g., contiguous areas within a distribution pipeline consisting of mains, services and other appurtenances; areas with common materials or environmental factors), and for which similar actions likely would be effective in reducing risk.

(d) *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).

(e) *Measure performance, monitor results, and evaluate effectiveness.*

(1) Develop and monitor performance measures from an established baseline to evaluate the effectiveness of its IM program. 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 as required by §192.703(c) of this subchapter (or total number of leaks if all leaks are repaired when found), categorized by cause;

(ii) Number of excavation damages;

(iii) Number of excavation tickets (receipt of information by the underground facility operator from the notification center);

(iv) Total number of leaks either eliminated or repaired, categorized by cause;

(v) Number of hazardous leaks either eliminated or repaired as required by §192.703(c) (or total number of leaks if all leaks are repaired when found), categorized by material; and

(vi) Any additional measures the operator determines are needed to evaluate the effectiveness of the operator's IM program in controlling each identified threat.

(f) *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 five years. The operator must consider the results of the performance monitoring in these evaluations.

(g) *Report results.* Report, on an annual basis, the four measures listed in paragraphs (e)(1)(i) through (e)(1)(iv) of this section, as part of the annual report required by §191.11. An operator also must report the four measures to the state pipeline safety authority if a state exercises jurisdiction over the operator's pipeline.

§ 192.1009 What must an operator report when compression couplings fail?

Each operator must report, on an annual basis, information related to failure of compression couplings, excluding those that result only in non-hazardous leaks, as part of the annual report required by §191.11 beginning with the report submitted March 15, 2011. This information must include, at a minimum, location of the failure in the system, nominal pipe size, material type, nature of failure including any contribution of local pipeline environment, coupling manufacturer, lot number and date of manufacture, and other information that can be found in markings on the failed coupling. An operator also must report this information to the state pipeline safety authority if a state exercises jurisdiction over the operator's pipeline.

§ 192.1011 What records must an operator keep?

An operator must maintain records demonstrating compliance with the requirements of this subpart for at least 10 years. The records must include copies of superseded integrity management plans developed under this subpart.

§ 192.1013 When may an operator deviate from required periodic inspections under this part?

(a) 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 subpart.

(b) 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. 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.

(c) An operator may implement an approved reduction in the frequency of a periodic inspection or test only where the operator has developed and implemented an integrity management program that provides an equal or improved overall level of safety despite the reduced frequency of periodic inspections.

§ 192.1015 What must a master meter or small liquefied petroleum gas (LPG) operator do to implement this subpart?

(a) *General.* No later than August 2, 2011 the operator of a master meter system or a small LPG operator must develop and implement an IM program that includes a written IM plan as specified in paragraph (b) of this section. The IM program for these pipelines should reflect the relative simplicity of these types of pipelines.

(b) *Elements.* A written integrity management plan must address, at a minimum, the following elements:

(1) *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 (for example, design, construction, operations or maintenance activities).

(2) *Identify threats.* The operator must consider, at minimum, the following categories of threats (existing and potential): Corrosion, natural forces, excavation damage, other outside force damage, material or weld failure, equipment failure, and incorrect operation.

(3) *Rank risks.* The operator must evaluate the risks to its pipeline and estimate the relative importance of each identified threat.

(4) *Identify and implement measures to mitigate risks.* The operator must determine and implement measures designed to reduce the risks from failure of its pipeline.

(5) *Measure performance, monitor results, and evaluate effectiveness.* The operator must monitor, as a performance measure, the number of leaks eliminated or repaired on its pipeline and their causes.

(6) *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 five years. The operator must consider the results of the performance monitoring in these evaluations.

(c) *Records.* The operator must maintain, for a period of at least 10 years, the following records:

(1) A written IM plan in accordance with this section, including superseded IM plans;

(2) Documents supporting threat identification; and

(3) 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.

6. OPERATION QUALIFACATIONS

6. OPERATOR QUALIFICATION (OQ)

Operators must have developed by April 27th, 2001 a plan that, when implemented, will assure a qualified work force. This is required for employees who perform tasks that meet the following criteria.

Is performed on a pipeline facility;
Is an operations or maintenance task;
Is performed as a requirement of this part; and
Affects the operation or integrity of the pipeline.

The plan must have been implemented by October 28th, 2002.

Distribution operators within the state of Ohio must have incorporated a timeline for incorporating new construction, including riser installation and service installation, into their Operator Qualification Plan by April 15, 2008. This applies to distribution operators and master meter operators only. It does not apply to transmission or gathering operators.

The Ohio Rural Natural Gas Co-Op Operator Qualification Plan is a separate Manual, but works in conjunction with the O&M Plan. A review of your OQ Plan should be included in the review of your O&M Plan every 15 months, but at least once each calendar year. The O&M review should specifically note that the OQ Plan review was included. In addition, your Operator Qualification Plan should be periodically reviewed for effectiveness of the plan. If significant changes are made to the plan, these must be reported to the PUCO and to PHMSA.

....

Subpart N–Qualification of Pipeline Personnel

192.801 Scope.

(a) This subpart prescribes the minimum requirements for operator qualification of individuals performing covered tasks on a pipeline facility.

(b) For the purpose of this subpart, a covered task is an activity, identified by the operator, that:
(1) Is performed on a pipeline facility;
(2) Is an operations or maintenance task;
(3) Is performed as a requirement of this part; and
(4) Affects the operation or integrity of the pipeline.

§192.803 Definitions.

Abnormal operating condition means a condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:
(a) Indicate a condition exceeding design limits; or
(b) Result in a hazard(s) to persons, property, or the environment.

Evaluation means a process, established and documented by the operator, to determine an individual's ability to perform a covered task by any of the following:
(a) Written examination;

(b) Oral examination;
(c) Work performance history review;
(d) Observation during:
(1) Performance on the job,
(2) On the job training, or
(3) Simulations;
(e) Other forms of assessment.

Qualified means that an individual has been evaluated and can:
(a) Perform assigned covered tasks; and
(b) Recognize and react to abnormal operating conditions.

[Amdt. 192-86, 64 FR 46865, Aug. 27, 1999, as amended by Amdt. 192-90, 66 FR 43523, Aug. 20, 2001]

§192.805 Qualification program.

Each operator shall have and follow a written qualification program. The program shall include provisions to:

(a) Identify covered tasks;

(b) Ensure through evaluation that individuals performing covered tasks are qualified;

(c) Allow individuals that are not qualified pursuant to this subpart to perform a covered task if directed and observed by an individual that is qualified;

(d) Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an incident as defined in Part 191;

(e) Evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task;

(f) Communicate changes that affect covered tasks to individuals performing those covered tasks;

(g) Identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed.

(g) Identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed;

(h) After December 16, 2004, provide training, as appropriate, to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities; and

(i) After December 16, 2004, notify the Administrator or a state agency participating under 49 U.S.C. Chapter 601 if the operator significantly modifies the program after the Administrator or state agency has verified that it complies with this section.

[Amdt. 192-86, 64 FR 46853, Aug. 27, 1999 as amended by Amdt. 192-100 (99), 70 FR 10322, Mar. 3, 2005]

§192.807 Recordkeeping.

Each operator shall maintain records that demonstrate compliance with this subpart.

(a) Qualification records shall include:
(1) Identification of qualified individual(s);
(2) Identification of the covered tasks the individual is qualified to perform;
(3) Date(s) of current qualification; and
(4) Qualification method(s).

(b) Records supporting an individual's current qualification shall be maintained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of five years.

§192.809 General.

(a) Operators must have a written qualification program by April 27, 2001. The program must be available for review by the Administrator or by a state agency participating under 49 U.S.C. Chapter 601 if the program is under the authority of that state agency.

(b) Operators must complete the qualification of individuals performing covered tasks by October 28, 2002.

(c) Work performance history review may be used as a sole evaluation method for individuals who were performing a covered task prior to October 26, 1999.

(d) After October 28, 2002, work performance history may not be used as a sole evaluation method.

(e) After December 16, 2004, observation of on-the-job performance may not be used as the sole method of evaluation.

[Amdt. 192-86, 64 FR 46853, Aug. 27, 1999 as amended by Amdt. 192-86A, 66 FR 43523, Aug. 20, 2001; Amdt. 192-100 (99), 70 FR 10322, Mar. 3, 2005]

7. PLACES TO FIND ADDITIONAL INFORMATION

7. PLACES TO FIND ADDITIONAL INFORMATION

A. The supplying Gas Company:

Address and name of contact are located in the Emergency Manual.

B. Consultant:

The consultant that prepared this manual is:

Utility Technologies International Corporation
4700 Homer Ohio Lane
Groveport, Ohio 43125

Office	614-482-8080
Fax	614-482-8070
UTI website	uti-corp.com

President - Hoby Griset P.E.
Email hgriset@uti-corp.com

Vice President Operations – Jason Julian
Email jjulian@uti-corp.com

Their background and experience allow them to handle all facets of natural gas system operations and are an excellent source.

C. State Regulatory Agency:

Ohio Public Utilities Commission
180 East Broad Street
Columbus, Ohio 43266
(614) 466-7542

D. State Gas Association

Ohio Gas Association
6100 Emerald Parkway
Dublin, Ohio 43016
(614) 659-5990 P
(614) 659-5993 F
www.ohiogasassoc.org
office@ohiogasassoc.org

Appendix A–Incorporated by Reference

I. *List of organizations and addresses.*

A. American Gas Association (AGA), 1515 Wilson Boulevard, Arlington, VA 22209.

B. American National Standards Institute (ANSI), 11 West 42nd Street, New York, NY 10036.

C. American Petroleum Institute (API), 1220 L Street, NW., Washington, DC 20005.

D. The American Society of Mechanical Engineers (ASME), United Engineering Center, 345 East 47th Street, New York, NY 10017.

E. American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, West Conshohocken, PA 19428.

F. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park Street, NW., Vienna, VA 22180.

G. National Fire Protection Association (NFPA), 1 Batterymarch Park, P.O. Box 9101, Quincy, MA 02269-9101.

II. *Documents incorporated by reference. (Numbers in parentheses indicate applicable editions.)*

A. American Gas Association (AGA):

1. AGA Pipeline Research Committee, Project PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December **22,** 1989).

B. American Petroleum Institute (API):

1. API Specification 5L "Specification for Line Pipe" (41st edition, 1995).
2. API Recommended Practice 5L1 "Recommended Practice for Railroad Transportation of Line Pipe" (4th edition, 1990).
3. API Specification 6D "Specification for Pipeline Valves (Gate, Plug, Ball, and Check Valves)" (21st edition, 1994).
4. API Standard 1104 "Welding of Pipelines and Related Facilities" (18th edition, 1994).

C. American Society for Testing and Materials (ASTM):

1. ASTM Designation: A 53 "Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless" (A53-96).
2. ASTM Designation: A106 "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service" (A106-95).
3. ASTM Designation: A333/A333M "Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service" (A333/A333M-94).
4. ASTM Designation: A372/A372M "Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels" (A372/A372M-95).
5. ASTM Designation: A381 "Standard Specification for Metal-Arc-Welded Steel Pipe for Use With High-Pressure Transmission Systems" (A381-93).
6. ASTM Designation: A671 "Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures" (A671-94).
7. ASTM Designation: A672 "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures" (A672-94).
8. ASTM Designation: A691 "Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures" (A691-93).
9. ASTM Designation: D638 "Standard Test Method for Tensile Properties of Plastics" (D638-96).
10. ASTM Designation: D2513 "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings" (D2513-87 edition for §192.63(a)(1), otherwise D2513-96a).

11. ASTM Designation: D2517 "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (D2517-94).

12. ASTM Designation: F1055 "Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing" (F1055-95).

D. The American Society of Mechanical Engineers (ASME):

1. ASME/ANSI B16.1 "Cast Iron Pipe Flanges and Flanged Fittings" (1989).

2. ASME/ANSI B16.5 "Pipe Flanges and Flanged Fittings" (1988 with October 1988 Errata and ASME/ANSI B16.5a-1992 Addenda).

3. ASME/ANSI B31G "Manual for Determining the Remaining Strength of Corroded Pipelines" (1991).

4. ASME/ANSI B31.8 "Gas Transmission and Distribution Piping Systems" (1995).

5. ASME Boiler and Pressure Vessel Code, Section I "Power Boilers" (1995 edition with 1995 Addenda).

6. ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 "Pressure Vessels" (1995 edition with 1995 Addenda).

7. ASME Boiler and Pressure Vessel Code, Section VIII, Division 2 "Pressure Vessels: Alternative Rules" (1995 edition with 1995 Addenda).

8. ASME Boiler and Pressure Vessel Code, Section IX "Welding and Brazing Qualifications" (1995 edition with 1995 Addenda).

E. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS):

1. MSS SP-44-96 "Steel Pipe Line Flanges" (includes 1996 errata)(1996).

2. [Reserved].

F. National Fire Protection Association (NFPA):

1. NFPA 30 “Flammable and Combustible Liquids Code” (1996).

2. ANSI/NFPA 58 “Standard for the Storage and Handling of Liquefied Petroleum Gases”(1995).

3. ANSI/NFPA 59 “Standard for the storage and Handling of Liquefied Petroleum Gases at Utility Gas Plants”(1995).

4. ANSI/NFPA 70 “National Electrical Code” (1996).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-3, 35 FR 17659, Nov. 17, 1970; Amdt. 192-12, 38 FR 4760, Feb. 22, 1973; Amdt. 192-17, 40 FR 6345, Feb. 11, 1975; Amdt. 192-17C, 40 FR 8188, Feb. 26, 1975; Amdt. 192-18, 40 FR 10181, Mar. 5, 1975; Amdt. 192-19, 40 FR 10471, Mar. 6, 1975; Amdt. 192-22, 41 FR 13589, Mar. 31, 1976; Amdt. 192-32, 43 FR 18553, May 1, 1978; Amdt. 192-34, 44 FR 42968, July 23, 1979; Amdt. 192-37, 46 FR 10157, Feb. 2, 1981; Amdt. 192-41, 47 FR 41381, Sept. 20, 1982; Amdt. 192-42, 47 FR 44263, Oct. 7, 1982; Amdt. 192-51, 51 FR 15333, Apr. 23, 1986; Amdt. 192-61, 53 FR 36793, Sept. 22, 1988; Amdt. 192-62, 54 FR 5625, Feb. 6, 1989; Amdt. 192-64, 54 FR 27881, July 3, 1989; Amdt. 192-65, 54 FR 32344, Aug. 7, 1989; Amdt. 192-68, 58 FR 14519, Mar. 18, 1993; Amdt. 192-76, 61 FR 26121, May 24, 1996; Amdt. 192-78, 61 FR 28770, June 6, 1996; Amdt. 192-78C, 61 FR 41019, Aug. 7, 1996; Amdt. 192-84, 63 FR 7721, Feb. 17, 1998; Amdt. 192-84A, 63 FR 38757, July 20, 1998]

8. GENERAL MAINTENANCE

8. GENERAL MAINTENANCE SCHEDULE

General Maintenance Schedule

Item	O&M	Code	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
			Month Scheduled											
Patrolling	4.D Dist. 4.S Trans.	192.721 Dist. 192.705 Trans.	X				X				X			
Gas Leak Detection Surveys	4.E Dist 4.S Trans.	192.723 Dist. 192.706 Trans.									X			
Pressure Regulator Stations	4.0 Dist.	192.739, .741, .743 Dist.									X			
Key Valve Maintenance	4.I Dist. 4.S Trans.	192.747 Dist. 192.745 Trans.									X			
Odorization of Gas	4.Q	192.625	X			X			X			X		
Corrosion Control Survey, Underground	4.K	192.465									X			
Corrosion Control Survey, Atmospheric	4.K	192.481									X			
Review and Update of O&M Manual	1, 4.A	192.605			X									
Training of O&M Procedures	1, 4.A	192.605			X									
Keep Map Up-to-date		192.605			X									
Continuing Surveillance	4.D	192.613	X				X				X			
Review and Update of Damage Prev. Programs	4.C	192.614										X		
Review and Update of Emergency Manual	1, 4.A, EM 2.	192.615			X									
Training of Emergency Procedures	1, 4.A, EM 2.	192.615			X									
Implement Public Education Program	EM 4.	192.616		X						X				
Review Line Markers	4.C	192.707									X			
Exposed Piping Examination	4.K	192.459	As Needed											
Testing of Piping	4.L.9	192.505, .507, .509 Dist. & Trans. 192.511, .513 Dist.	As Needed											

9. FUSION PROCEDURES

9. FUSION PROCEDURES

Please refer to the Ohio Rural Natural Gas Co-Op Welding Manual

Exhibit DK-5

Ohio Rural Natural Gas Co-Op
Contractor Qualification Program
Pipeline Operator Qualifying System

Operations and Maintenance, Employee Training, Qualifying and Documentation Program and Contractor Compliance Program

UTI

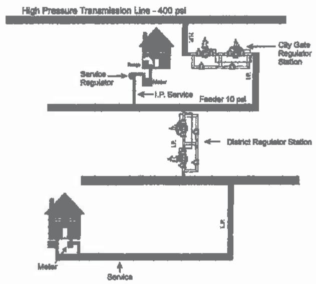
Pipeline Contractor Covered Task Qualification Program

Version 12.0
Updated 4/22/16

Table of Contents

Introduction

This Operator Qualification Plan sets forth the Ohio Rural Natural Gas Co-Op program for complying with the pipeline safety regulations found in 49 CFR 192, Subpart N.



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1. Federal & State of Ohio Statutes & Regulations

1. Federal Statutes and Regulations

A. Statutory Authority and Scope

This Operator Qualification Plan (OQ Plan) sets forth Ohio Rural Natural Gas Co-Op (The Company) policy and procedures for compliance with the minimum pipeline safety regulations defined in 49 CFR Part 192, Subpart N. Specifically, this OQ Plan outlines the requirements for evaluating the qualifications of individuals performing certain operating and maintenance tasks on the company's gas distribution pipeline system and facilities. It is the company's responsibility to ensure that all employees and contractors are qualified in accordance with this plan. Adequate records will be maintained to demonstrate that employees and contractors performing the covered tasks identified in this plan are qualified and have satisfied the requirements of the OQ Plan.

B. Text of 49 CFR 192 Subpart N

Subpart N—Qualification of Pipeline Personnel

§ 192.801 Scope.

(a) This subpart prescribes the minimum requirements of operator qualification of individuals performing covered tasks on a pipeline facility.
(b) For the purpose of this subpart, a covered task is an activity, identified by the operator, that:

- (1) Is performed on a pipeline facility;
- (2) Is an operations or maintenance task;
- (3) Is performed as a requirement of this part; and
- (4) Affects the operation or integrity of the pipeline.

§ 192.803 Definitions.

Abnormal operating condition means a condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:

- (a) Indicate a condition exceeding design limits; or
- (b) Result in a hazard(s) to persons, property, or the environment.

Evaluation means a process established and documented by the operator, to determine an individual's ability to perform a covered task by any of the following:
(a) Written examination;
(b) Oral examination;
(c) Work performance history review;
(d) Observation during:
  (1) Performance on the job.
  (2) On the job training.
  (3) Simulations; or
(e) other forms of assessment.

Qualified means that an individual has been evaluated and can:
(a) Perform assigned covered tasks; and
(b) Recognize and react to abnormal operating conditions.

§ 192.805 Qualification Program.

Each operator shall have and follow a written qualification program. The program shall include provisions to:
(a) Identify covered tasks;
(b) Ensure through evaluation that individuals performing covered tasks are qualified;
(c) Allow individuals that are not qualified pursuant to this subpart to perform a covered task if directed and observed by an individual that is qualified;
(d) Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an incident as defined in part 191;
(e) Evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task;
(f) Communicate changes that affect covered tasks to individuals performing those covered tasks;
(g) Identify those covered tasks and the intervals at which evaluation of the individual's qualifications are needed;
(h) After December 16, 2004, provide training, as appropriate, to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities; and
(i) After December 16, 2004, notifies the Administrator or a state agency participating under 49 U.S.C. Chapter 601 if the operator significantly modifies the program after the Administrator or state agency has verified that it complies with this section.

§ 192.807 Recordkeeping.

Each operator shall maintain records that demonstrate compliance with this subpart.

(a) Qualification records shall include:

(1) Identification of qualified individual(s);

(2) Identification of the covered tasks the individual is qualified to perform;

(3) Date(s) of current qualification;

(4) Qualification method(s).

(b) Records supporting an individual's current qualification shall be maintained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of five years.

§ 192.809 General.

(a) Operators must have a written qualification program by April 27, 2001. The program must be available for review by the Administrator or by a state agency participating under 49 U.S.C. Chapter 601 if the program is under the authority of that state agency.

(b) Operators must complete the qualification of individuals performing covered tasks by October 28, 2002.

(c) Work performance history review may be used as a sole evaluation method for evaluating for individuals who were performing a covered task prior to October 26, 1999.

(d) After October 28, 2002, work performance history may not be used as a sole evaluation method.

(e) After December 16, 2004, observation of on-the-job performance may not be used as the sole method of evaluation.

C. State of Ohio Requirements

The Public Utilities Commission of Ohio (PUCO) has enacted an Operator Qualification requirement that exceeds the federal requirements found in 49 CFR 192 Subpart N. This requirement (PUCO order 05-463-GA-COI) states in part that "…distribution operators shall incorporate new construction, including riser installation, as part of their operator qualification requirements…".

All personnel performing new construction pursuant to 49 CFR Part 192 within the State of Ohio must be qualified in accordance with this Operator Qualification Program. Covered tasks required for performing new construction in Ohio shall be the same covered tasks as if the work was being performed as an operations or maintenance task.

2. Purpose of Plan and
Effective Date

2. Purpose of Plan and Effective Date

A. Purpose of Plan

The purpose of this document is to outline the methods to be used in developing, implementing and maintaining a comprehensive Operator Qualification Program that will reduce the risk of accidents or incidents on the company's pipeline facilities through the use of qualified individuals. The stated purpose will be accomplished by:

- Establishing objective criteria for determining qualifications;
- Using various evaluation methods to demonstrate the qualified person's proficiency at a covered task and ability to recognize and respond to abnormal situations encountered;
- Maintaining sufficient records to ensure continued compliance; and,
- Identifying the organizational responsibilities required to ensure that The Company utilizes and maintains a qualified work force.

B. Effective Date

This written qualification program plan is effective April 27, 2001. As required, evidence that all company and contractor employees performing covered tasks will be available no later than October 28, 2002.

3. Definitions and
Qualifications Criteria

3. Definitions and Qualification Criteria

All interpretations and definitions regarding the Operator Qualification Program and the OQ Plan shall be based on the Final OQ Rule contained in part **1. B.** of this plan (49 CFR Part 192, Subpart N) and/or any subsequent changes to Subpart N that may be made by the U.S. Department of Transportation pursuant to its jurisdictional authority.

In determining which tasks performed by company employees and the employees of contractors hired by the company require proof of qualification, the following definitions have been applied.

A *Covered Task* is an activity identified by the operator that:
(1) Is performed on a pipeline facility;
(2) Is an operations or maintenance task;
(3) Is performed as a requirement of 49 CFR Part 192; and
(4) Affects the operation or integrity of the pipeline.

Abnormal operating condition means a condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may indicate a condition exceeding design limits or result in a hazard(s) to persons, property, or the environment.

Evaluation means a process, established and documented by the operator, to determine an individual's ability to perform a covered task by any of the following:
(a) Written examination;
(b) Oral examination;
(c) Work performance history review[1];
(d) Observation during:
  (1) Performance on the job;
  (2) On the job training,
  (3) Simulations, or
(e) Other forms of assessment.
Effective April 1, 2007, a combination of evaluation methods is necessary to insure that both knowledge (examination) and skills (observation) are evaluated, except for tasks where examination alone is sufficient to determine an individual's qualifications for the task concerned.

Qualified means that an individual has been evaluated and can:
(a) Perform assigned covered tasks; and
(b) Recognize and react to abnormal operating conditions.

(The foregoing definitions are taken from §192.801 and §192.803.)

Initial and Transitional Qualification Period is the period from August 27, 1999 through October 28, 2002, during which work performance history review can be used as the sole or primary qualification evaluation method for company and contractor employees performing identified covered tasks, provided that such employees were performing the covered task prior to October 26, 1999

[1] Work performance history review may be used as a sole evaluation method for individuals who were performing a covered task prior to August 27, 1999. After October 28, 2002, work performance history may not be used as a sole evaluation method.

4. Plan Implementation &
Assignment of Plan
Mgt. Responsibilities

4. Plan Implementation and Assignment of Plan Management Responsibilities

In order to effectively implement and maintain the Operator Qualification Program, the company has established the following procedures and identified the person(s) listed to ensure proper administration:

A. Coordinator of Operator Qualification

- The designation given to the person responsible for all aspects of the Operator Qualification Program. The duties include:

  (1) establishing and chairing the Operator Qualification Committee;
  (2) serving as a contact point for both internal personnel and outside entities (including regulatory bodies and contractors);
  (3) maintaining accountability for the Operator Qualification Program;
  (4) distribution of up-to-date copies of the plan to appropriate personnel;
  (5) notifying the Administrator of the Office of Pipeline Safety or state agency participating under 49 U.S.C. Chapter 601 (jurisdictional authority) if significant modifications are made to this Operator Qualification plan after the Administrator or state agency has verified that it complies with 49 CFR Part 192, Subpart N;
  (6) verifying that, after December 16, 2004, training is provided as appropriate to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of the pipeline facilities;
  (7) convening the Operator Qualification Committee in the event of a pending merger or acquisition to establish and implement procedures for managing qualifications of individuals performing identified covered tasks during OQ program integration following a merger or acquisition;
  (8) ensuring that all meeting and activity dates are on time; and
  (9) notification of all employees and contractors at least 30 days in advance of qualification expiration or change in status

The person assigned these responsibilities will have significant operational experience.

The Coordinator of Operator Qualification is Darryl Knight.

B. Operator Qualification Committee

The Operator Qualification Committee is a group of individuals responsible for monitoring and evaluating the effectiveness of the Operator Qualification Program and overseeing necessary adjustments. This includes identification of covered tasks. At a minimum, the committee will include the following members:

- The Coordinator of Operator Qualification (Chair)
- Darryl Knight, President, is responsible for Operations and Maintenance activities
- Darryl Knight, President, is responsible for engineering and construction activities
- Darryl Knight, President, is responsible for training activities
- other members as needed based on their expertise and the needs of the committee.

C. Evaluation Committee

The Evaluation Committee is a group of individuals who determine the qualification requirements of a *specific covered task* and methods to evaluate personnel to ensure that they are qualified to perform that task. The Evaluation Committee consists of the following:

- Coordinator of Operator Qualification (chair)
- Darryl Knight, management representative familiar with the specific covered task, and materials and equipment used in the pipeline system.
- Darryl Knight, an experienced employee who currently performs the task or has recently performed the task and is considered to have the required expertise to perform the task. This individual must also be thoroughly familiar with the materials used in all portions of the pipeline system, the O & M Plan and the Emergency Response Plan.

D. Specific Responsibilities

1. Darryl Knight is responsible for ensuring that all individuals who perform covered tasks identified by this plan are qualified as prescribed in the plan.
2. Darryl Knight is responsible for verifying that each individual who performs a covered task, whether a company employee, or an employee of a contractor is qualified under this plan, and that the individual's qualification documents are on file with the company prior to the start of any construction or maintenance work.
3. Darryl Knight is responsible for scheduling and managing any training or qualification activities required for company employees as prescribed in this written qualification program.

5. Method for Identifying Covered Tasks

5. Method for Identifying Covered Tasks

A. Personnel Responsible

The Covered Task list will be developed by the Operator Qualification Committee and will be maintained by Darryl Knight.

B. Actions to be Taken

- Covered tasks will be identified using a four part test consisting of the following criteria:

  (1) Is it performed on a pipeline facility?
  (2) Is it an operations or maintenance task?
  (3) Is it performed pursuant to a requirement in 49 CFR 192?
  (4) Does it affect the operation or integrity of the pipeline?

- The members of the responsible committee will compile an initial task list by researching the existing operational and procedural documents, such as the Operation and Maintenance Manual, Emergency Plan, Job Descriptions, Contractor Agreements, and other documents. In addition, lists by trade associations or other outside groups may be considered.
- Using the Appendix B Covered Task Evaluation Form the committee evaluates each identified task based on the four criteria listed above to determine applicability.
- The current list of covered tasks will be maintained in Appendix A of this OQ Plan Document.
- For each task identified as a "covered task," a Covered Task Evaluation Form is generated (Appendix B) and members of an Evaluation Committee for that specific task are identified.
- The committee identifies the skill, knowledge and any sub-tasks required to perform each covered task and forwards the Covered Task Evaluation Form to the Operator Qualification Committee.

C. Records

- Appendix A- List of Identified Covered Tasks
- Appendix B- Covered Task Evaluation Form

6. Methods for Assuring Qualification of Personnel

6. Methods for Assuring Qualification of Personnel

A. Personnel Responsible

The Evaluation Committee is responsible for the selection of the appropriate method of evaluation and qualified evaluator(s) for each covered task. The appropriate method will be indicated as defined for Transitional and Initial Evaluation. The committee shall establish the appropriate time period and method(s) for all subsequent evaluations and re-evaluations.

B. Evaluation Methods

The evaluation method(s) will verify that the employee or contractor performing a covered task has the skills to perform and knowledge to recognize and respond to abnormal operating conditions identified on the Task Assessment Form. The evaluation methods may include but are not limited to the following:

- written examination
- oral examination
- work performance history review (for eligible employees during the initial and transitional period)
- observation during
    1) performance on the job,
    2) on the job training, or
    3) simulations
- other forms of assessment.

Each evaluation method used shall incorporate means to verify that persons who perform identified covered tasks on the pipeline facilities can recognize and properly react to abnormal operating conditions specific to the tasks they perform.

C. Actions to be Taken

The company is responsible for ensuring the qualification of all individuals working on the pipeline system, ***including contract personnel.*** The provisions contained in this program will ensure that each individual performing covered tasks for the company is qualified. Personnel identified as evaluators need not be qualified under the rule, but will possess the required knowledge to ascertain an individual's ability to perform covered tasks and recognize and react to abnormal operating conditions that might surface while performing those tasks.

- The Evaluation Committee will receive a Covered Task Evaluation Form from the Operator Qualification Committee listing the specific task to be addressed. The two committees may work jointly or separately.

- The Evaluation Committee reviews the description for each task including abnormal operating conditions and reactions to those conditions. Changes are made as required.

- The Evaluation Committee also analyzes the skills and knowledge required to perform each identified task and forwards its determinations for final review by the Operator Qualification Committee. Changes are made as required.

- The Operator Qualification Committee decides on the appropriate method of evaluation and provides rationale as to why that method is most appropriate. The appropriate method(s) and intervals for re-evaluation are also identified for each covered task.

- In the event that the method of evaluation involves testing, the Committee:

  ☐ Is responsible for developing the testing and qualification program, and/or
  ☒ Has selected Utility Technologies International, Inc. as the company's third-party testing agency and has reviewed and approved the selected testing instrument, and/or
  ☐ Will use other means to do training and/or qualification programs

The designated test shall be identified on the Covered Task Evaluation Form.

- The Evaluation Committee develops a list of requirements for evaluators. This may include work experience, technical expertise, educational background, or applicable certifications or training received.

- The Evaluation Committee identifies individuals who can serve as Qualified Evaluators based on the requirements identified.

D. Records

Documentation of the work of the Qualification Committee and Evaluation Committee are detailed in:
- Appendix A-List of Identified Covered Tasks
- Appendix B-Covered Task Evaluation Form

7. Maint. of Personnel
Qualification Records

7. Maintenance of Personnel Qualification Records

Darryl Knight is responsible for establishing a system to maintain records that demonstrate compliance with the rule. Accordingly, all records maintained will satisfy the following minimal requirements:

- Records will include identifying information (name, employee number, etc.)
- Records will include the name of the covered task(s) the individual is qualified to perform, the qualification dates, and method of qualification/evaluation.
- All records will be maintained as active while the individual is qualified to perform the covered tasks.
- All previous records will be retained for at least a period of five years.
- Record keeping will be kept in the company's headquarters offices and available at all times to company managers, supervisors and credentialed representatives of the Office of Pipeline Safety of the U.S. Department of Transportation and/or any other authority having jurisdiction.
- Certificates of qualification [X] will [ ] will not be issued.
- Wallet cards [X] will [ ] will not be issued.

8. Conditions for Use of Non-Qualified Personnel

8. Conditions for Use of Non-Qualified Personnel

This section does not apply to contractor personnel.

A. Personnel Responsible

Darryl Knight is responsible for informing supervisors about the status of their employees with respect to covered tasks.

The Supervisors are responsible for ensuring that all employees reporting to them are aware of the current list of covered tasks and of the requirement of this OQ Plan pertaining to these tasks. The Supervisors are to immediately report to the Darryl Knight if they have reason to believe that any of their subordinates are no longer qualified to perform a task.

A list of Covered Tasks as identified by the company will be provided to all employees and contractors. The documentation provided with the Covered Task List will require employee and contractor acknowledgement by date and signature that they are expected to know those covered tasks that may only be performed by persons qualified under this OQ Plan. Any employee observing any of these covered tasks being performed on the company's pipeline facilities by a non-qualified person *not under direct supervision of a qualified person,* MUST immediately report this condition to his/her immediate supervisor.

B. Procedures for Use of Non-Qualified Personnel

- Individuals who are not qualified to perform a covered task may do so as long as a qualified individual directly observes the performance and is able to take immediate corrective action when necessary. The qualified person monitoring the activities of non-qualified persons is ultimately responsible for the performance of the task. The number of employees working under the direct supervision of a qualified employee shall be kept to a minimum.
- The Coordinator of Operator Qualification will provide the Operations Manager with an annual report indicating the status of their employees with respect to covered functions.
- The Coordinator of Operator Qualification will provide the Operations Manager with immediate updates to this report in the event that the status of an individual changes using the Operator Qualification Status Update Record, Appendix D.
- The Operations Manager will ensure that this information is passed down to the immediate supervisor of the personnel responsible for performing the covered task.

- The immediate supervisor will use all of this information in issuing work assignments to ensure that at least one qualified individual is directly involved in the performance of the covered task or closely monitoring the non-qualified individuals performing the covered task.
- In situations where non-qualified personnel are performing a covered task under the supervision of a qualified individual, the immediate supervisor will inform the qualified individual of his/her obligations to directly monitor the work and when necessary, to take immediate corrective action.
- In situations where non-qualified personnel are performing a covered task under the supervision of a qualified individual, and the non-qualified personnel does not speak the language of the qualified individual, arrangements must be made to provide for effective communications between the qualified and non-qualified individuals before performing the covered task. If effective communications cannot be established, a qualified individual must perform the covered task.
- The number of employees working under the direct supervision of a qualified employee shall be kept to a minimum.

9. Methods for Verifying Qualifications of Contractor Personnel

9. Methods for Verifying Qualifications of Contractor Personnel

Prior to commencement of any work on a company pipeline system, a contractor whose employees perform any identified covered task must submit:

1. A copy of the contractor's covered task qualifying program, and
2. Documentation of the qualifications of all contractor employees performing identified covered tasks as defined in **Section 3** of this qualifying program to the Coordinator of Operator Qualification. The qualification requirements of the contractor plan must be equal to or more stringent than the requirements of this pipeline operator qualifying program.
3. Ohio Rural Natural Gas Co-Op will accept the operator qualifications from the following companies; Cobra Pipeline, Orwell Trumbull Pipeline, Dominion East Ohio Gas, Columbia Gas, Big Oats Oilfield Supply, Quality Boring, Great Plains Exploration.

The Coordinator of Operator Qualification is responsible for:

1. examining and certifying contractor qualification programs and contractor employee qualification documentation,
2. forwarding a list containing the names of certified contractor employees and their corresponding covered task qualifications to the local pipeline system operating manager(s).

Contractor personnel performing any identified covered task under this program must carry proof of their qualifications, which may be a wallet card that identifies:

1. each of the individual's current covered task qualifications,
2. method of qualification applied,
3. period that qualifications are valid;
4. name of employer and a phone number where a current copy of the contractor's written qualification plan and employee qualification documents may be obtained.

Local pipeline system operating manager(s) and supervisors are responsible for verifying that each contractor employee is qualified to perform any identified covered task assigned to the contractor employee, or that a qualified person is provided by the contractor to directly inspect and supervise the contractor employee at all times.

10. Evaluating Qualifications Following an Incident or Accident

10. Evaluating Qualifications Following an Incident or Accident

A. Personnel Responsible

In the event of an accident an individual must be re-evaluated if there is reason to believe that the individual's performance contributed to an incident (as defined in Part 191) or accident (as defined in Part 192).

Line management is responsible for the investigation of any incident or accident.

Darryl Knight is responsible for re-evaluating the individuals involved in any incident or accident.

B. Action to Be Taken

- Should a line manager have reason to believe that an individual's performance of a covered task contributed to an incident or accident, he/she immediately forwards the name of the individual(s) to the Coordinator of Operator Qualification.
- The Coordinator of Operator Qualification convenes that Darryl Knight is responsible for that specific task.
- The committee decides which evaluation method is appropriate for the re-qualification of an individual for the specific covered task (which may be different than the original method).
- The committee will identify a qualified evaluator and that individual will conduct the evaluation.
- In the event that the individual's performance is deemed satisfactory by the evaluator, no change in status will be indicated.
- If the individual's performance is deemed unsatisfactory, the evaluator will notify the Coordinator of Operator Qualification who will generate an Operator Qualification Status Update Sheet informing Darryl Knight that the individual is no longer qualified to perform the covered task. At that point, re-qualification of the individual is subject to the terms set forth by Darryl Knight for that particular covered task.

C. Records

All results from evaluations performed following an incident or accident will be maintained as part of the training records for that individual.

11. Review of Quals. and re-qualification of Personnel

11. Review of Qualifications and Re-qualification of Personnel

A. Personnel Responsible

The Evaluation Committee(s) is (are) responsible for identifying the appropriate re-qualification interval for each covered task.

B. Procedures to Establish Subsequent Qualification Intervals and Method(s)

- The Evaluation Committee(s) identifies whether and when an individual's qualification to perform a covered task is subject to subsequent evaluation at appropriate intervals. This decision will be based on the nature of the task itself and task related factors which may include:
  - (a) Difficulty or complexity of task performance
  - (b) Importance of proper task performance in terms of the consequences of inadequate task performance
  - (c) Frequency of task performance
- When the Evaluation Committee considers an Operator Qualification Covered Task, the members of the committee must, as a part of the process, determine re-qualification requirements for the tasks and develop plans for this as needed. This process is considered in Appendix E of this plan.
- Intervals for subsequent qualification will not exceed three (3) years for any one covered task.

C. Records

Appendix B – Covered Task Evaluation Form

12. Examination of Qualifications For Cause

12. Examination of Qualifications For Cause

A. Personnel Responsible

Darryl Knight, is responsible for monitoring performance of covered tasks in the field.

The Evaluation Committee for the task in question is responsible for re-evaluating the individual.

B. Actions to be Taken

- Should a line manager have reason to believe that an individual is no longer qualified to perform the task, the manager is to forward the name of the individual to the Coordinator of Operator Qualification.
- The Coordinator of Operator Qualification convenes the Evaluation Committee responsible for that specific task.
- The committee decides which evaluation method is appropriate for the re-qualification of the individual for the specific covered task (which may be different than the original method).
- The committee will identify a qualified evaluator and that individual will conduct the evaluation.
- In the event that the individual's performance is deemed satisfactory by the evaluator, no change in status will be indicated.
- If the individual's performance is deemed unsatisfactory, the evaluator will notify the Coordinator of Operator Qualification who will generate an Operator Qualification Status Update Sheet informing Darryl Knight, that the individual is no longer qualified to perform the covered task. At that point, re-qualification of the individual is subject to the terms set forth by the Evaluation Committee for that particular covered task.

C. Records

All results from evaluations performed following the unsatisfactory performance of a task will be maintained as part of the training record for that individual.

13. Review of Quals. After a Change in Regs, Ops. or Maint. Procedures

13. Review of Qualifications After a Change in Regulations, Operating or Maintenance Procedures

A. Personnel Responsibility

The Coordinator of Operator Qualification is responsible for identifying and communicating information on substantive changes so individuals performing the tasks in question will be made aware.

The Evaluation Committee is responsible for revising the evaluation process to include the impact of such changes. The Evaluation Committee will make a determination as to the need to re-evaluate individuals as a result of the changes.

B. Actions to be Taken

There are numerous ways in which internal or external changes may affect the way a covered task is performed. Such changes include:

(1) Changes to the company's policies or procedures
(2) Changes in applicable regulations
(3) Changes in technology
(4) Changes in suppliers

- The Coordinator of Operator Qualification will establish and maintain a method for collecting, evaluating and disseminating information regarding changes that may affect the covered tasks identified by the Operator Qualification Committee.
- When appropriate, the Coordinator of Operator Qualification will convene the Evaluation Committee if it is deemed that the covered task in question is significantly affected by internal or external changes.
- The Evaluation Committee will assess the effect that the changes will have on the task and make adjustment as necessary. These adjustments could involve anything from informing qualified individuals of the changes to requiring complete re-evaluation.
- The revisions are approved by the Coordinator of Operator Qualification, subject to the approval of the company's upper management.
- If a significant change results, the Operator Qualification Committee and the Coordinator of Operator qualification shall make appropriate dated revisions to this OQ Plan. The Coordinator shall notify the Administrator of OPS or the appropriate state jurisdictional authority of any revisions.
-

Appendix A
List of Identified Covered Tasks

FAX # UTI 614-482-8070 / MAY 18, 2016 10:43

Date of This Identified Covered Task List: Oct. 26, 2002 (last revision: 5/7/08)

Evaluation Committee Members: Darryl Knight

Revision May 18, 2016 x DCK

The tasks ***checked below*** have been identified as "Covered Tasks" by applying the 49 CFR 192, Subpart N "Four Part Test" for the pipeline operator/contractor named above:

✓ (check all covered tasks that apply to your situation)

✓	CE-1	Weld on Steel Pipelines, 49 CFR 192.225, 192.231, 192.235, 192.245
	CE-2	Visually Inspect Pipe Welds, 49 CFR 192.241, 192.243
	CE-3	Perform Non-Destructive Tests on Steel Welds, 49 CFR 192.241, 192.243
✓	CF-1	Join Plastic Pipe with Heat Fusion
✓	CF-1.1	Join Plastic Pipe with Butt Fusion, 49 CFR 192.123, 192.273, 192.281, 192.285, 192.287
✓	CF-1.2	Join Plastic Pipe with Socket Fusion, 49 CFR 192.123, 192.273, 192.281, 192.285, 192.287
✓	CF-1.3	Join Plastic Pipe with Saddle Fusion, 49 CFR 192.123, 192.273, 192.281, 192.285, 192.287
✓	CF-1.4	Join Plastic Pipe with Electrofusion, 49 CFR 192.123, 192.273, 192.281, 192.285, 192.287
✓	CF-2	Join Plastic Pipe with Mechanical Fittings
	CF-2.1	Join Plastic Pipe with Threaded Nut Compression End Fittings, 49 CFR 192.123, 192.273, 192.281, 192.285, 192.287
✓	CF-2.2	Join Plastic Pipe with Stab-Type Mechanical Fittings, 49 CFR 192.123, 192.273, 192.281, 192.285, 192.287
✓	CF-2.3	Join Plastic Pipe with Mechanical Compression Fittings, 49 CFR 192.123, 192.273, 192.281, 192.285, 192.287
	CF-3	Join Copper Pipe for Gas Distribution, 49 CFR 192.279
	CF-4	Join Plastic Pipe with Solvent Cement, 49 CFR 192.273, 192.281, 192.283, 192.285, 192.287, 192.311
✓	CF-5	Visually Inspect Polyethylene Pipe Joints for Indicators of Proper Construction/Assembly, 49 CFR 192.123, 192.273, 192.281, 192.283, 192.285, 192.287
	CF-6	Install Tubing and Fittings for Instrumentation, Control, and Sampling, 49 CFR 192.203, 192.279
✓	CF-7	Join Pipe with Flange Assembly, 49 CFR 192.147

✓	CG-1	Verify Excavating and Backfilling Operations that Minimize Excavation Damage to Pipeline Facilities, 49 CFR 192.307, 192.317, 192.319, 192.321, 192.325, 192.327, 192.361, 192.461, 192.614
✓	CG-2	Identify Basic Installation Methods for Mains and Transmission Pipelines, 49 CFR 192.307, 192.313, 192.315, 192.317, 192.319, 192.321, 192.323, 192.325, 192.327, 192.707
✓	CG-3	Install Aboveground Pipelines, 49 CFR 192.161, 192.307, 192.317, 192.479, 192.481, 192.707
✓	CG-4	Install Mains and Transmission Pipelines Using Trenchless Methods, 49 CFR 192.307, 192.321, 192.325, 192.327
✓	CG-5	Moving In-Service Pipelines, 49 CFR 192.319, 192.321, 192.323, 192.325, 192.327192.459, 192.605, 192.614, 192.615, 192.707
✓	CH-1	Install Customer Gas Meter and Regulator Sets, 49 CFR 192.353, 192.355, 192.357, 192.359
✓	CH-2	Install Customer Gas Service Lines, 49 CFR 192.151, 192.361, 192.363, 192.365, 192.367, 192.369, 192.373, 192.375, 192.377, 192.379, 192.381
✓	CH-3	Deactivate Gas Metering Services, 49 CFR 192.727
✓	CH-4	Install Residential Customer Service Line Valves, 49 CFR 192.363, 192.365, 192.381, 192.383
✓	CH-5	Maintenance of Service Valves Upstream of Customer Meter (in development), 49 CFR 192.363, 192.365
✓	CI-1	Perform Pipe-to-Soil Potential Surveys on Effectively Coated Buried or Submerged Pipelines, 49 CFR 192.463
✓	CI-2	Determine Areas of Active Corrosion Using Close Interval Survey Methods, 49 CFR 192.453, 192.465
✓	CI-3	Measure Soil Resistivity, 49 CFR 192.453, 192.465
✓	CI-4	Inspect the External Condition of Exposed Buried Metal Piping to Determine if Repair or Replacement is Necessary, 49 CFR 192.459, 192.461(a), 192.483, 192.485, 192.487, 192.489
—	CI-5	Inspect and Maintain Rectifiers, 49 CFR 192.465
✓	CI-6	Inspect for the Effects of Interference Current, 49 CFR 192.465, 192.473
✓	CI-7	Install Test Leads to Monitor and Control External Corrosion, 49 CFR 192.465, 192.469, 192.471
✓	CI-8	Install and Test Insulation to Control External Corrosion by Electrical Isolation, 49 CFR 192.467
✓	CI-9	Inspect for Evidence of Internal Corrosion, 49 CFR 192.475, 192.477
✓	CI-10	Inspect and Monitor Exposed Piping for Evidence of Atmospheric Corrosion, 49 CFR 192.479, 192.481
✓	CI-11	Install Sacrificial Anodes and Test Stations, 49 CFR 192.465, 192.469
✓	CI-12	Measure the Extent of Corrosion on Pipeline Facilities, 49 CFR 192.459, 192.475, 192.477, 192.481

✓	CI-13	Identify Procedures Basic to Inspecting, Applying, and Repairing Pipeline Coatings, 49 CFR 192.459, 192.461
—	CI-14	Obtain and Shipping Gas Samples, 49 CFR 192.475, 192.477
✓	CI-15	Troubleshoot In-Service Cathodic Protection Systems, 49 CFR 192.463
✓	CK-1	Uprate a Pipeline, 49 CFR 192.105, 192.121, 192.553, 192.555, 192.557, 192.619, 192.621, 192.623
✓	CL-1	Tap Pipelines Under Pressure, 49 CFR 192.151, 192.627
✓	CL-1a	Hot Tapping Pipelines Using Self-Tapping Tees, 49 CFR 192.627
✓	CL-1b	Bagging and Stopping Low Pressure Pipe with Bag, Stopper, or Stopple, 49 CFR 192.151, 192.627
✓	CL-2	Purge Pipelines (Small and Large Diameter), 49 CFR 192.629
✓	CL-3	Odorizer Inspection, Testing, and Preventive/Corrective Maintenance, 49 CFR 192.625
✓	CL-3a	Monitor Odorant Levels, 49 CFR 192.625
—	CL-4	Monitor and Regulate the Flow and Pressure of Gas from Remote Locations, 49 CFR 192.201, 192.619, 192.621, 192.623, 192.631, 192.741
✓	CL-5	Perform Hot Tapping Operations on Plastic Pipe, 49 CFR 192.151(a), 192.627
✓	CL-6	Inspect , Test, and Maintain Actuators, 49 CFR 192.179, 192.181, 192.745, 192.747
	CL-7	Inspect, Test, and Maintain Programmable Logic Controllers, 49 CFR 192.605B, 10(iii), 192.739
✓	CM-1	Perform Patrol and Leakage Surveys on Gas Pipeline Facilities, 49 CFR 192.5, 192.613, 192.705, 192.706, 192.721, 192.723
✓	CM-2	Locate and Mark Underground Facilities, 49 CFR 192.614, 192.707
✓	CM-3	Pressure Testing Gas Pipelines, 49 CFR 192.503, 192.505, 192.507, 192.509, 192.511, 192.513, 192.725
✓	CM-4	Inspect and Test Pressure Limiting Stations, Relief Devices, and Pressure Regulating Devices, 49 CFR 192.201, 192.731, 192.739, 192.743, 192.749, 192.751
✓	CM-5	Inspect, Service, and Operate Line Valves, 49 CFR 192.179, 192.181, 192.745, 192.747
✓	CM-5a	Inspect Emergency Valves, 49 CFR 192.745, 192.747, 192.803
✓	CM-5b	Valve Corrective Maintenance, 49 CFR 192.747
	CM-6	Monitor Compressor Station Gas Leak Detection Equipment, 49 CFR 192.735, 192.736
✓	CM-7	Prevent Accidental Ignition, 49 CFR 192.751
✓	CM-8	Make Field Repairs on Gas Pipelines, 49 CFR 192.245, 192.307, 192.309, 192.311, 192.703, 192.711, 192.713, 192.715, 192.717
	CM-9	Repair and Protect Cast Iron Pipe, 49 CFR 192.275, 192.489, 192.753, 192.755
✓	CM-10	Abandon or Deactivate Gas Pipeline Facilities, 49 CFR 192.727

✓	CM-11	Recognize and React to Generic Abnormal Operating Conditions, 49 CFR 192.751
✓	CM-12	Launch and Receive Pipeline Pigs, 49 CFR 192.150
—	CM-13	Investigate Reported Gas Leaks and Odors in Buildings
✓	CM-14	Inspect Vault Conditions, 49 cFR 192.749, 192.751
—	CM-15	Operate and Maintain Compressor Station Components, 49 CFR 192.167, 192.169, 192.171, 192.173, 192.199, 192.201, 192.605(a)(b)(6)(7), 192.731, 192.743
✓	CM-16	Inspect, Test, and Maintain Sensing Devices, 49 CFR 192.739, 192.741, 192.743
—	CM-17	Squeeze-Off Steel Pipe, 49 CFR 192.615
✓	CM-18	Station Emergency Shut Down System: Inspection, Testing, and Corrective Maintenance, 49 CFR 192.167, 192.171, 192.731, 192.736
✓	CM-19	Installing and Maintaining Customer Pressure Regulating, Pressure Limiting, and Pressure Relief Devices: Large Commercial and Industrial, 49 CFR 192.199, 192.743
✓	CM-20	Reciprocating Compressor Inspection, Testing, and Corrective Maintenance, 49 CFR 192.731
✓	CM-23	Measure and Characterize Mechanical Damage on Installed Pipe and Components, 49 CFR 192.307, 192.309
✓	CO-1	Conduct Indirect Pipe Inspections, 49 CFR 192.925, 192.947
✓	CO-2	Conduct Direct Pipe Examinations, 49 CFR 192.927, 192.947

Approved by:

Signature: Daryl L. Knight

Title:

Date: 5/18/16

Appendix A List of Identified Covered Tasks – Utility Series

Date of This Identified Covered Task List Oct. 26, 2002 (last revision: 5/7/08)

Evaluation Committee Members:
Darryl Knight

The tasks ***checked below*** have been identified as "Covered Tasks" by applying the 49 CFR 192, Subpart N "Four Part Test" for the pipeline operator/contractor named above:

✓ (check all covered tasks that apply to your situation)

✓	Task	E-1	Weld on steel pipelines, 49 CFR 192.235, 192.241, 192.245
✓	Task	E-2	Test welds using non-destructive process(es), 49 CFR 192.243
✓	Task	F-1	Join plastic pipe with heat fusion, 49 CFR 192.281, 192.287
✓	Task	F-2	Join plastic pipe with mechanical fittings, 49 CFR 192.281, 192.287
✓	Task	F-3	Join copper pipe, 49 CFR 192.279
✓	Task	G-1	Verifying excavation & backfilling operations to minimize damage, 49 CFR 192.317, 192.319, 192.325, 192.327, 192.361, 192.373, 192.461, 192.614
✓	Task	G-2	Horizontal Directional Drilling, 49 CFR 192.307, 192.313, 192.315, 192.317, 192.319, 192.321, 192.323, 192.325, 192.701
✓	Task	G-3	Boring by other methods, 49 CFR 192.161, 192.307, 192.317, 192.479, 192.481, 192.707
✓	Task	H-1	Install domestic meter and regulator sets, 49 CFR 192.357
✓	Task	H-2	Install domestic service lines, 49 CFR 192.361, 192.365, 192.367, 192.369
✓	Task	I-1(1-4)	I-1.1 Perform pipe-to-soil potential surveys on effectively coating buried or submerged pipelines I-1.2 Determine areas of active corrosion on buried or submerged metal piping using pipe-to-soil potential I-1.3 Determine areas of active corrosion on buried or submerged metal piping using a surface potential survey I-1.4 Examine the external condition of exposed buried metal piping to determine if repair or replacement is necessary, 49 CFR 192.455, 192.457, 192.459, 192.465, 192.467, 192.613

	Task	I-1(5-8)	I-1.5 Inspect rectifiers I-1.6 Inspect interference current bonds I-1.7 Install test leads to monitor and control external corrosion I-1.8 Install insulators to control external corrosion by electrical isolation, 49 CFR 192.455, 192.457, 192.459, 192.465, 192.467, 192.613
	Task	I-1(9-10)	I-1.9 Inspect for evidence of internal corrosion I-1.10 Monitor internal corrosion control of piping when transporting corrosive gas, 49 CFR 192.475, 192.477, 192.613
	Task	I-1(11-12)	I-1.11 Inspect exposed piping for evidence of atmospheric corrosion I-1.12 Monitoring atmospheric corrosion control of exposed piping, 49 CFR 192.479, 192.481, 192.613
	Task	I-1(13,14,15)	I-1.13 Determine remedial measures for controlling corrosion on transmission lines I-1.14 Determine remedial measures for controlling corrosion on distribution lines I-1.15 Determine remedial measures for controlling corrosion on cast iron and ductile iron pipelines, 49 CFR 192.485, 192.487, 192.489, 192.613
	Task	I-1(16-17)	I-1.16 Attach anode leads to metal piping I-1.17 Apply / repair pipeline coating, 49 CFR 192.471, 192.613
	Task	I-1 Combo	I-1.7 Install test leads to monitor and control external corrosion I-1.8 Install insulators to control external corrosion by electrical isolation I-1.11 Inspect exposed piping for evidence of atmospheric corrosion I-1.12 Monitoring atmospheric corrosion control of exposed piping I-1.16 Attach anode leads to metal piping I-1.17 Apply / repair pipeline coating, 49 CFR 192.455, 192.457, 192.459, 192.465, 192.467, 192.471, 192.479, 192.481, 192.613
	Task	L-1	Tap pipelines under pressure, 49 CFR 192.627
	Task	L-2	Purge gas lines, 49 CFR 192.629
	Task	L-3	Establish and maintain proper odorant levels in natural gas systems, 49 CFR 192.625
	Task	L-3s	Monitoring odorant levels, 49 CFR 192.625
	Task	M-1	Perform leakage and patrolling surveys, 49 CFR 192.613, 192.705, 192.706, 192.721, 192.723
	Task	M-2	Locate and mark underground pipeline facilities WITH electronic equipment, 49 CFR 192.613, 192.707

	Task	M-2(a)	Locate and mark w/o electronic locating equipment, 49 CFR 192.613, 192.707
	Task	M-3	Test service lines, 49 CFR 192.725
	Task	M-4	Inspect and test pressure limit stations, relief devices and pressure regulating stations, 49 CFR 192.731, 192.739, 192.741, 192.743, 192.749
✓	Task	M-5	Maintain line valves in gas transmission/distribution piping, 49 CFR 192.745, 192.747
	Task	M-5.1	Operate Valves – Ball, Plug, Gate, Butterfly, 49 CFR 192.745, 192.747
	Task	M-6	Monitor compressor station gas detection equipment, 49 CFR 192.736
	Task	M-7FR	Prevent accidental ignition, First Responder 49 CFR 192.751
	Task	M-8 (Includes I-1.9 & I-1.10)	M-8 Installing/replacing & repairing natural gas piping I-1.9 Inspect for evidence of internal corrosion I-1.10 Monitor internal corrosion control of piping when transporting corrosive gas, 49 CFR 192.475, 192.477, 192.711, 192.713, 192.715, 192.717
	Task	M-9	Repair/protect cast iron pipe, 49 CFR 192.753, 192.755
✓	Task	M-10	Abandon/deactivate gas pipeline systems, 49 CFR 192.727

Approved by:

Signature: Laura Tristano

Title: Compliance Manager

Date: Aug 1, 2016

Appendix B
Covered Task Evaluation Forms

This page has been left blank intentionally.

You will need to copy the following 2 pages and fill them out for each task that you have chosen from Appendix A.

Appendix B Covered Task Evaluation Form

Name & Location of Pipeline System: Ohio Rural Natural Gas Co-Op
7001 Center Street
Mentor, OH 44060

Covered Task:
No. CF-1.1 Task Name: JOIN PLASTIC PIPE W/BUTT FUSION

Evaluation Committee Members:
Darryl Knight

Application of 49 CFR 192, Subpart N "Four Part Test"

Operator Qualification Task list Referenced to CFR 49, Part 192 Subpart	Task performed on a pipeline facility	An operations or maintenance task	Performed as a requirement of this subpart	Affects the Operations or integrity of the pipeline
Task	✓	✓	✓	✓

Reference Criteria: (See Appendix A)

Task ☑ **is** a covered task for the operation of the pipeline named above.
☐ **is not** a covered task for the operation of the pipeline system named above.

Task ☐ **can** be performed by a non-qualified person under direct supervision
Task ☑ **cannot** be performed by a non-qualified person under direct supervision

Personnel designated to perform the covered task: (Check both boxes if both apply.)
☑ Qualified Company Employees
☑ Qualified Contractor Employees

Designated Operating Company Employee Job Titles or Descriptions (if Applicable):

Method(s) of Evaluation Selected for This Identified Task:

Method	Code	Documentation of Method
☑ UTI/ITS Qualification Module	(WE)	☑ *UTI/ITS Qualification Module – Written* Testing and Hands On if required ☐ Other Written Exam (Specify Name or Source)
☐ Oral Examination	(OE)	(Specify Name or Source)
☐ Work Performance History Review		(Specify)
☐ Observation during 1) Performance on the job; 2) On the Job training, 3) Simulations, or		(Specify)
X Other Form of Assessment		(Specify) NiSource qualifications

Re-qualification Requirements:

☐ Re-qualification is required (indicate interval): 12 months

☐ Re-qualification is not required

List of Qualified Evaluators:

Approved by:

Signature	Title	Date
Darryl L. Knight	PRESIDENT	5/18/16

Name & Location of Pipeline System: Ohio Rural Natural Gas Co-Op
7001 Center Street
Mentor, OH 44060

Covered Task:
No. OH-2 Task Name: Install Customer Service Lines

Evaluation Committee Members:
Darryl Knight

Application of 49 CFR 192, Subpart N "Four Part Test"

Operator Qualification Task list Referenced to CFR 49, Part 192 Subpart	Task performed on a pipeline facility	An operations or maintenance task	Performed as a requirement of this subpart	Affects the Operations or integrity of the pipeline
Task	✓	✓	✓	✓

Reference Criteria: (See Appendix A)

Task ☑ **is** a covered task for the operation of the pipeline named above.
☐ **is not** a covered task for the operation of the pipeline system named above.

Task ☐ **can** be performed by a non-qualified person under direct supervision
Task ☑ **cannot** be performed by a non-qualified person under direct supervision

Personnel designated to perform the covered task: (Check both boxes if both apply.)
☑ Qualified Company Employees
☐ Qualified Contractor Employees

Designated Operating Company Employee Job Titles or Descriptions (if Applicable):

Method(s) of Evaluation Selected for This Identified Task:

Method	Code	Documentation of Method
☑ UTI/ITS Qualification Module	(WE)	☑ *UTI/ITS Qualification Module – Written* Testing and Hands On if required ☐ Other Written Exam (Specify Name or Source)
☐ Oral Examination	(OE)	(Specify Name or Source)
☐ Work Performance History Review		(Specify)
☐ Observation during 1) Performance on the job; 2) On the Job training, 3) Simulations, or		(Specify)
X Other Form of Assessment		(Specify) NiSource qualifications

Re-qualification Requirements:

☐ Re-qualification is required (indicate interval): 12 months
☐ Re-qualification is not required

List of Qualified Evaluators:

Approved by:

Signature	Title	Date
Darryl L. Knight	PRESIDENT	5/18/16

Appendix C
Mutual Aid Agreement

Name & Location of Pipeline System	Ohio Rural Natural Gas Co-Op 7001 Center Street Mentor, OH 44060
Effective Date of This Appendix	4/22/16

<u>Working Definition for the purpose of this Operator Qualification Program</u>–Mutual Aid Agreements with other pipeline operating companies or organizations are established to provide for pipeline system repairs and other activities related to restoring customer service after an emergency or catastrophic event affecting the pipeline system to the extent that the operating company is unable to restore normal operations through the use of its own personnel and/or resources in a timely manner.

The Coordinator of Operator Qualification and any other company employee(s) designated by the Coordinator of Operator Qualification will review all existing and any proposed Mutual Aid Agreements to ensure that such agreements are consistent with this Operator Qualification Program.

Prior to renewing or initiating Mutual Aid Agreements, the participating companies or organizations will provide mutually satisfactory documentation to one another to demonstrate that the companies and organizations have written Operator Qualification Programs. Mutual Aid Agreements will provide that all employees of participating companies or organizations participating in activities under the agreements shall be qualified to perform covered tasks in accordance with the participating companies' or organizations' OQ Plans and Programs.

Mutual Aid Agreements are in affect as of the date shown above with the following companies and/or organizations.

Orwell Trumbell Pipeline LLC	
Company/Organization Name	Company/Organization Name
Jessica Carothers.	
Mutual Aid Contact	Mutual Aid Contact
3511 Lost Nation Rd #213	
Mailing Address	Mailing Address
Willoughby, OH 44094	
City, State, Zip Code	City, State, Zip Code
440.255.1945	
Company/Organization Phone Number	Company/Organization Phone Number
440.255.1985	
Company/Organization Fax Number	Company/Organization Fax Number
440.655-7017	
Mutual Aid Contact Phone Number	Mutual Aid Contact Phone Number
1.866.534.6809	
Emergency Contact Phone Number(s)	Emergency Contact Phone Number(s)

Name & Location of Pipeline System	Ohio Rural Natural Gas Co-Op 7001 Center Street Mentor, OH 44060
Effective Date of This Appendix	4/22/16

Working Definition for the purpose of this Operator Qualification Program--Mutual Aid Agreements with other pipeline operating companies or organizations are established to provide for pipeline system repairs and other activities related to restoring customer service after an emergency or catastrophic event affecting the pipeline system to the extent that the operating company is unable to restore normal operations through the use of its own personnel and/or resources in a timely manner.

The Coordinator of Operator Qualification and any other company employee(s) designated by the Coordinator of Operator Qualification will review all existing and any proposed Mutual Aid Agreements to ensure that such agreements are consistent with this Operator Qualification Program.

Prior to renewing or initiating Mutual Aid Agreements, the participating companies or organizations will provide mutually satisfactory documentation to one another to demonstrate that the companies and organizations have written Operator Qualification Programs. Mutual Aid Agreements will provide that all employees of participating companies or organizations participating in activities under the agreements shall be qualified to perform covered tasks in accordance with the participating companies' or organizations' OQ Plans and Programs.

Mutual Aid Agreements are in affect as of the date shown above with the following companies and/or organizations.

Company/Organization Name	Cobra Pipeline	Big Oats Field Supply
Mutual Aid Contact	Jessica Carothers	John Cessna
Mailing Address	3511 Lost Nation Rd Ste 5	38700 Pelton Rd.
City, State, Zip Code	Willoughby, OH 44094	Willoughby, OH 44094
Company/Organization Phone Number	440·255·1945	440·942·1800
Company/Organization Fax Number	440·255·1985	440·942·1818
Mutual Aid Contact Phone Number	440·655·7047	440·567·1170
Emergency Contact Phone Number(s)	1·866·534·6809	440·567·1170

Appendix D
Qualification Status Update
Record

D.O.T. FUSION / MECHANICAL QUALIFICATION

M257-24726C-18
Unique ID Number
David O. Stanish
Name
Ohio Rural Natural Gas Co-Op
Company Name

This card certifies that this individual has been tested and qualified according to the requirements of D.O.T. 49CFR Part 192 and the applicable tasks identified on the back of the card.

D.O.T. FUSION / MECHANICAL QUALIFICATION

TW88-1B305F-83
Unique ID Number
Tyler E. Lette
Name
Ohio Rural Natural Gas Co-Op
Company Name

This card certifies that this individual has been tested and qualified according to the requirements of D.O.T. 49CFR Part 192 and the applicable tasks identified on the back of the card.

D.O.T. FUSION / MECHANICAL QUALIFICATION

7096-08C12F-08
Unique ID Number
George M. Papp
Name
Ohio Rural Natural Gas Co-Op
Company Name

This card certifies that this individual has been tested and qualified according to the requirements of D.O.T. 49CFR Part 192 and the applicable tasks identified on the back of the card.

D.O.T. FUSION / MECHANICAL QUALIFICATION

D952-2701A2-33
Unique ID Number
Jack J. McCormick
Name
Ohio Rural Natural Gas Co-Op
Company Name

This card certifies that this individual has been tested and qualified according to the requirements of D.O.T. 49CFR Part 192 and the applicable tasks identified on the back of the card.

D.O.T. FUSION / MECHANICAL QUALIFICATION

6071-2D31E6-44
Unique ID Number
Ed K. Sebring
Name
Ohio Rural Natural Gas Co-Op
Company Name

This card certifies that this individual has been tested and qualified according to the requirements of D.O.T. 49CFR Part 192 and the applicable tasks identified on the back of the card.

D.O.T. FUSION / MECHANICAL QUALIFICATION

ZG37-23A060-66
Unique ID Number
Ryan J. McCormick
Name
Ohio Rural Natural Gas Co-Op
Company Name

This card certifies that this individual has been tested and qualified according to the requirements of D.O.T. 49CFR Part 192 and the applicable tasks identified on the back of the card.

UTI

Utility Technologies International Corp.
4700 Homer Ohio Lane
Groveport, OH 43125 (614) 482-8080

Name: David O. Stanish

Fusion / Mechanical Qualification Date: 4/27-28/2016

X CF-1 Join Plastic Pipe with Heat Fusion Exp. 4/27/17
X CF-2 Join Plastic Pipe with Mechanical Fittings Exp. 4/27/17

X CF-6 Install Tubing and Fittings for Instrumentation,
Control and Sampling Exp. 4/28/19
X CF-7 Join Plastic Pipe with Flange Assembly Exp. 4/27/19
X CL-1a Hot Tapping Pipelines Using Self-Tapping Tees Exp. 4/28/19

Dates above expire one year from the qualification date. The person listed above has been successfully tested and evaluated on knowledge, skills and ability.

UTI

Utility Technologies International Corp.
4700 Homer Ohio Lane
Groveport, OH 43125 (614) 482-8080

Name: Tyler E. Lette

Fusion / Mechanical Qualification Date: 4/27-28/201

X CF-1 Join Plastic Pipe with Heat Fusion Exp. 4/27/17
X CF-2 Join Plastic Pipe with Mechanical Fittings Exp. 4/27/17

X CF-6 Install Tubing and Fittings for Instrumentation,
Control and Sampling Exp. 4/28/19
X CF-7 Join Plastic Pipe with Flange Assembly Exp. 4/27/19
X CL-1a Hot Tapping Pipelines Using Self-Tapping Tees Exp. 4/28/19

Dates above expire one year from the qualification date. The person listed above has been successfully tested and evaluated on knowledge, skills and ability.

UTI

Utility Technologies International Corp.
4700 Homer Ohio Lane
Groveport, OH 43125 (614) 482-8080

Name: George M. Papp

Fusion / Mechanical Qualification Date: 4/27-28/2016

X CF-1 Join Plastic Pipe with Heat Fusion Exp. 4/27/17
X CF-2 Join Plastic Pipe with Mechanical Fittings Exp. 4/27/17

X CF-6 Install Tubing and Fittings for Instrumentation,
Control and Sampling Exp. 4/28/19
X CF-7 Join Plastic Pipe with Flange Assembly Exp. 4/27/19
X CL-1a Hot Tapping Pipelines Using Self-Tapping Tees Exp. 4/28/19

Dates above expire one year from the qualification date. The person listed above has been successfully tested and evaluated on knowledge, skills and ability.

UTI

Utility Technologies International Corp.
4700 Homer Ohio Lane
Groveport, OH 43125 (614) 482-8080

Name: Jack J. McCormick

Fusion / Mechanical Qualification Date: 4/27-28/201

X CF-1 Join Plastic Pipe with Heat Fusion Exp. 4/27/17
X CF-2 Join Plastic Pipe with Mechanical Fittings Exp. 4/27/17

X CF-6 Install Tubing and Fittings for Instrumentation,
Control and Sampling Exp. 4/28/19
X CF-7 Join Plastic Pipe with Flange Assembly Exp. 4/27/19
X CL-1a Hot Tapping Pipelines Using Self-Tapping Tees Exp. 4/28/19

Dates above expire one year from the qualification date. The person listed above has been successfully tested and evaluated on knowledge, skills and ability.

UTI

Utility Technologies International Corp.
4700 Homer Ohio Lane
Groveport, OH 43125 (614) 482-8080

Name: Ed K. Sebring

Fusion / Mechanical Qualification Date: 4/27-28/2016

X CF-1 Join Plastic Pipe with Heat Fusion Exp. 4/27/17
X CF-2 Join Plastic Pipe with Mechanical Fittings Exp. 4/27/17

X CF-6 Install Tubing and Fittings for Instrumentation,
Control and Sampling Exp. 4/28/19
X CF-7 Join Plastic Pipe with Flange Assembly Exp. 4/27/19
X CL-1a Hot Tapping Pipelines Using Self-Tapping Tees Exp. 4/28/19

Dates above expire one year from the qualification date. The person listed above has been successfully tested and evaluated on knowledge, skills and ability.

UTI

Utility Technologies International Corp.
4700 Homer Ohio Lane
Groveport, OH 43125 (614) 482-8080

Name: Ryan J. McCormick

Fusion / Mechanical Qualification Date: 4/27-28/2016

X CF-1 Join Plastic Pipe with Heat Fusion Exp. 4/27/17
X CF-2 Join Plastic Pipe with Mechanical Fittings Exp. 4/27/17

X CF-6 Install Tubing and Fittings for Instrumentation,
Control and Sampling Exp. 4/28/19
X CF-7 Join Plastic Pipe with Flange Assembly Exp. 4/27/19
X CL-1a Hot Tapping Pipelines Using Self-Tapping Tees Exp. 4/28/19

Dates above expire one year from the qualification date. The person listed above has been successfully tested and evaluated on knowledge, skills and ability.

OQ Task Information

Utility Technologies International, Corporation 4700 Homer Ohio Lane, Groveport, OH 43125 614-482-8080

Ohio Rural Natural Gas Co-Op

7001 Center Street
Mentor, OH 44060 440-255-5198

***E = Exam, O = Observation by Simulation (No Observation on M-7 required)**
Prefixes of "NI_" are NISource-specific modules, suffixes of "Propane" are propane modules
***Task Criteria = Criteria Established by Specific Veriforce Contractor Criteria**

List of Test Modules

F1F2 - Fusion and Mechanical Joining
F-2 - Mechanical Joining of Polyethylene Pipe
G-1 - Excavation and Backfilling
G-2 - Directional Boring
G-3 - Boring by other methods
H-1 - Install meter and regulator sets
H-2 - Install service lines
I-1 - Controlling Corrosion: Installing Test Leads Elec. Isolation, Monitoring Atmospheric Corrosion, Attach Anodes, Apply/Repair Coatings
I-1(1-4)-Monitoring Corrosion
I-1(a) - Evaluation and Application of Corrosion Control
I-1(b) - Reading Test Stations, Eval. App. of Above Ground Corrosion Control
I-1(c) - Evaluation and Application of Above Ground Corrosion Control
I-1(d) - Monitoring Corrosion Control
L-1/L-1(a) - Tapping and Bagging Pipelines
L-1(b) - Tapping Pipelines
L-1(c) - Tapping Pipeline w. Self Tapping Tees
L2 - Purge Gas Lines
L-2(S)- Purge Gas Lines (small)
L-2 No Restrictions - Purge Gas Lines Large and Small
L-2(a) - Purge Service Lines
L-3 - Establish and Maintain Odorant
L-3(s)- Monitor Odorant Levels

M-1 - Perform Patrol and Leak Surveys on Gas Pipeline Facilities
M-2 - Locate and mark underground facilities
M-3 - Test service lines
M-4 - Inspect and test pressure limiting stations
M-5 - Maintain and Operate Valves
M-5.1 - Operate Valves
M-6 Monitor Compressor Station Equipment
M-7 / Ni_M-7 / M-7FR - Prevent Accidental Ignition / Accidental Ignition First Responder
M-8 - Installing, repairing replacing gas piping (includes I-1.9, I-1.10 inspect/monitor for internal corrosion)
M-9 - Repair/ Protect Cast Iron Pipe
M10 - Abandon/deactivate gas pipelines
M10(a)-Abandon/deactivate service line piping
NFGC / IFGC- National Fuel Gas Code / International Fuel Gas Code
GDS 1.1s - Identifying Basic Properties of Fuel Gases
GDS 1.2s- Measuring Natural Gas in a Distribution System
GDS 5.1s- Identifying Fundamentals of Venting and Ventilation
GDS 6.15 - Reestablishment of Natural Gas Service
GDS 4.2P - Service Line Installer Module including Mechanical Joining
Last SLI - Last date of Service Line Installation qualification
Either GDS 4.2P one day class or Combination of F2, H1, H2, I1, M3, M7, M10
COM 1.3 Identifying Operating Characteristics of Gas Engines and Reciprocating Compressor Units

UTI OQ Task Information

Utility Technologies International, Corporation 4700 Homer Ohio Lane, Groveport, OH 43125 614-482-8080

Ohio Rural Natural Gas Co-Op

7001 Center Street
Mentor, OH 44060 440-255-5198

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ITS Compliance Series Modules:

CI-1 - Perform Pipe-to-Soil Potential Surveys on Effectively Coated Buried or Submerged Pipeline
CI-2 - Monitor Cathodically Protected Pipelines - Close Interval Survey
CI-3 - Monitor Cathodically Protected Pipelines - Soil Resistivity
CI-4 - Inspect External Conditions of Exposed Buried Metal Piping to Determine if Repair or Replacement is Nec..
CI-5 - Inspect / Maintain Rectifiers
CI-6 - Inspect for the Effects of Interference Current
CI-7 - Install Test Leads to Monitor and Control External Corrosion
CI-8 - Install / Test Insulation to Control External Corrosion by Electrical Isolation
CI-9 - Inspect for Evidence of Internal Corrosion
CI-10 - Inspect/Monitor Exposed Pipeing for Evidence of Atmospheric Corrosion
CI-11 - Installing Sacrificial Anodes and Test Stations
CI-12 - Measure the Extent of Corrosion on Pipeline Facilities
CI-13 - Identify Procedures Basic to Inspecting, Applying and Repairing Pipeline Coatings

MOST COMMON VERIFORCE COMMON COVERED TASKS (USED BY NISOURCE TRANSMISSION):

CCT 208 - Plastic Pipe Joining: Butt Fusion
CCT 209 - Plastic Pipe Joining: Mechanical Joining
CCT 210 - Plastic Pipe Joining: Electrofusion Joining
CCT 213 - Joining of Steel Pipe - Threaded and Flanged Connections
CCT 216 - Joining of Steel Pipe - Compression Couplings
CCT 217 - Small Diameter Metal Tubing and Fitting Installation
CCT 401 - Exam of Bruied Pipe when Exposed
CCT 402 - Apply Approved Coatings to Above Ground Piping
CCT 403 - Apply Approved Coatings to Below Ground Piping
CCT 404 - Protection of Coating When Backfilling and From Below Ground Supports
CCT 412 - Install CP Leads on Pipeline Using Exothermic Weld
CCT 426 - Inspect Pipe Coating with Holiday Detector
CCT 501 - Conduct Pressure Test to Substantiate MAOP
CCT 502 - Pressure Test on Pipe at Pressure <100 psig
CCT 605 - Locate Line/Install Temp Markings
CCT 614 - Purge Pipeline w. Air or Inert Gas
CCT 703 - Placing/Maintaining Line Markers
CCT 704 - Permanent Field Repair by Grinding

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MOST COMMON VERIFORCE DOMINION COVERED TASKS:

OQ-141 - Visual Inspection for Atmospheric Corrosion
OQ-146 - Visual Inspection of Atmospheric Corrosion - Interior Service Lines
OQ-151 - Visual Inspection of Buried Pipe and Components When Exposed
OQ-161 - Visual Inspection for Internal Corrosion
OQ-201 - Visual Inspection of Installed Pipe and Components for Mechanical Damage
OQ-681 - Joining Plastic Pipe-Stab fittings
OQ-691 - Joining Pipe - non-bottom out fittings
OQ-701 - Joining Pipe - bottom out fittings
OQ-711 - Joining Pipe - compression couplings
OQ-721 - Joining Pipe - threaded joints
OQ-731 - Joining pipe - Flanges
OQ-751 - Joining pipe - Manual Butt Fusion
OQ-761 - Joining pipe - Hydraulic Butt Fusion
OQ-781 - Joining pipe - Electrofusion
OQ-961 - Above Ground Supports Anchors - Inspection, Preventive Corrective Maintenance
OQ-981 - Backfilling
OQ-991 - Coating Application and Repair - Brushed or Rolled
OQ-1001 - Coating Application and Repair - Sprayed
OQ-1011 - External Coating Application and Repair - Wrapped
OQ-1700 - Abnormal Operating Conditions

INGAA OQ TASKS:	MEA OQ TASKS:
OQ095 -	PEF 0803.01
OQ160 -	PEF 1402.01
	PEF 1301.01, .02, .03
	PEF 0503.01 - Cathodic Protection Systems-Electrical Connections

Dominion OQ-076-GL - Installing Miscellaneous Fittings and Tubing for Natural Gas or Liquids

CONSOL ENERGY - VERIFORCE TASKS:

007OP - Operate Valves
213OP - Joining of Steel Pipe - Threaded and Flanged Connections
401OP - Examination of Buried Pipelines When Exposed
403OP - Apply Approved Coatings to Below Ground Piping
414OP - Inspect for Internal Corrosion Whenever Pipe is Removed
415OP - Monitoring for Internal Corrosion with Probes and Coupons
417OP - Atmospheric Corrosion Monitoring
421OP - Measurement of Depth of Pitting with Pit Gage
501OP - Conduct a Pressure Test
605OP - Locate Line / Install Temporary Marking of Buried Pipeline
607OP - Damage Prevention: Observation of Excavating and Backfilling
613OP - Purge Pipeline Facilities With Gas
614OP - Purge Pipeline Facilities with Air or Inert Gas
617OP - Locate Buried Facilities with an Electro-magnetic Device
618OP - Install Temporary Marking of Buried Pipeline
701OP - Patrolling Pipeline and Leakage Survey without Instrument
703OP - Placing / Maintaining Line Markers
716OP - Inspect, Maintain and Operate Valves

The covered tasks listed below have been identified as tasks that may be performed by qualified employees of the companies or organizations listed above under applicable Mutual Aid Agreements:

✓ (check all covered tasks that apply)

✓	CE-1	Weld on Steel Pipelines, 49 CFR 192.225, 192.231, 192.235, 192.245
–	CE-2	Visually Inspect Pipe Welds, 49 CFR 192.241, 192.243
–	CE-3	Perform Non-Destructive Tests on Steel Welds, 49 CFR 192.241, 192.243
✓	CF-1	Join Plastic Pipe with Heat Fusion
✓	CF-1.1	Join Plastic Pipe with Butt Fusion, 49 CFR 192.123, 192.273, 192.281, 192.285, 192.287
	CF-1.2	Join Plastic Pipe with Socket Fusion, 49 CFR 192.123, 192.273, 192.281, 192.285, 192.287
✓	CF-1.3	Join Plastic Pipe with Saddle Fusion, 49 CFR 192.123, 192.273, 192.281, 192.285, 192.287
✓	CF-1.4	Join Plastic Pipe with Electrofusion, 49 CFR 192.123, 192.273, 192.281, 192.285, 192.287
✓	CF-2	Join Plastic Pipe with Mechanical Fittings
–	CF-2.1	Join Plastic Pipe with Threaded Nut Compression End Fittings, 49 CFR 192.123, 192.273, 192.281, 192.285, 192.287
✓	CF-2.2	Join Plastic Pipe with Stab-Type Mechanical Fittings, 49 CFR 192.123, 192.273, 192.281, 192.285, 192.287
✓	CF-2.3	Join Plastic Pipe with Mechanical Compression Fittings, 49 CFR 192.123, 192.273, 192.281, 192.285, 192.287
	CF-3	Join Copper Pipe for Gas Distribution, 49 CFR 192.279
–	CF-4	Join Plastic Pipe with Solvent Cement, 49 CFR 192.273, 192.281, 192.283, 192.285, 192.287, 192.311
✓	CF-5	Visually Inspect Polyethylene Pipe Joints for Indicators of Proper Construction/Assembly, 49 CFR 192.123, 192.273, 192.281, 192.283, 192.285, 192.287
–	CF-6	Install Tubing and Fittings for Instrumentation, Control, and Sampling, 49 CFR 192.203, 192.279
✓	CF-7	Join Pipe with Flange Assembly, 49 CFR 192.147
✓	CG-1	Verify Excavating and Backfilling Operations that Minimize Excavation Damage to Pipeline Facilities, 49 CFR 192.307, 192.317, 192.319, 192.321, 192.325, 192.327, 192.361, 192.461, 192.614
✓	CG-2	Identify Basic Installation Methods for Mains and Transmission Pipelines, 49 CFR 192.307, 192.313, 192.315, 192.317, 192.319, 192.321, 192.323, 192.325, 192.327, 192.707
✓	CG-3	Install Aboveground Pipelines, 49 CFR 192.161, 192.307, 192.317, 192.479, 192.481, 192.707

√	CG-4	Install Mains and Transmission Pipelines Using Trenchless Methods, 49 CFR 192.307, 192.321, 192.325, 192.327
√	CG-5	Moving In-Service Pipelines, 49 CFR 192.319, 192.321, 192.323, 192.325, 192.327192.459, 192.605, 192.614, 192.615, 192.707
√	CH-1	Install Customer Gas Meter and Regulator Sets, 49 CFR 192.353, 192.355, 192.357, 192.359
√	CH-2	Install Customer Gas Service Lines, 49 CFR 192.151, 192.361, 192.363, 192.365, 192.367, 192.369, 192.373, 192.375, 192.377, 192.379, 192.381
	CH-3	Deactivate Gas Metering Services, 49 CFR 192.727
√	CH-4	Install Residential Customer Service Line Valves, 49 CFR 192.363, 192.365, 192.381, 192.383
√	CH-5	Maintenance of Service Valves Upstream of Customer Meter (in development), 49 CFR 192.363, 192.365
√	CI-1	Perform Pipe-to-Soil Potential Surveys on Effectively Coated Buried or Submerged Pipelines, 49 CFR 192.463
√	CI-2	Determine Areas of Active Corrosion Using Close Interval Survey Methods, 49 CFR 192.453, 192.465
√	CI-3	Measure Soil Resistivity, 49 CFR 192.453, 192.465
√	CI-4	Inspect the External Condition of Exposed Buried Metal Piping to Determine if Repair or Replacement is Necessary, 49 CFR 192.459, 192.461(a), 192.483, 192.485, 192.487, 192.489
√	CI-5	Inspect and Maintain Rectifiers, 49 CFR 192.465
√	CI-6	Inspect for the Effects of Interference Current, 49 CFR 192.465, 192.473
√	CI-7	Install Test Leads to Monitor and Control External Corrosion, 49 CFR 192.465, 192.469, 192.471
√	CI-8	Install and Test Insulation to Control External Corrosion by Electrical Isolation, 49 CFR 192.467
√	CI-9	Inspect for Evidence of Internal Corrosion, 49 CFR 192.475, 192.477
√	CI-10	Inspect and Monitor Exposed Piping for Evidence of Atmospheric Corrosion, 49 CFR 192.479, 192.481
√	CI-11	Install Sacrificial Anodes and Test Stations, 49 CFR 192.465, 192.469
√	CI-12	Measure the Extent of Corrosion on Pipeline Facilities, 49 CFR 192.459, 192.475, 192.477, 192.481
√	CI-13	Identify Procedures Basic to Inspecting, Applying, and Repairing Pipeline Coatings, 49 CFR 192.459, 192.461
	CI-14	Obtain and Shipping Gas Samples, 49 CFR 192.475, 192.477
√	CI-15	Troubleshoot In-Service Cathodic Protection Systems, 49 CFR 192.463
√	CK-1	Uprate a Pipeline, 49 CFR 192.105, 192.121, 192.553, 192.555, 192.557, 192.619, 192.621, 192.623
√	CL-1	Tap Pipelines Under Pressure, 49 CFR 192.151, 192.627
√	CL-1a	Hot Tapping Pipelines Using Self-Tapping Tees, 49 CFR 192.627

✓	CL-1b	Bagging and Stopping Low Pressure Pipe with Bag, Stopper, or Stopple, 49 CFR 192.151, 192.627
✓	CL-2	Purge Pipelines (Small and Large Diameter), 49 CFR 192.629
✓	CL-3	Odorizer Inspection, Testing, and Preventive/Corrective Maintenance, 49 CFR 192.625
✓	CL-3a	Monitor Odorant Levels, 49 CFR 192.625
–	CL-4	Monitor and Regulate the Flow and Pressure of Gas from Remote Locations, 49 CFR 192.201, 192.619, 192.621, 192.623, 192.631, 192.741
✓	CL-5	Perform Hot Tapping Operations on Plastic Pipe, 49 CFR 192.151(a), 192.627
✓	CL-6	Inspect , Test, and Maintain Actuators, 49 CFR 192.179, 192.181, 192.745, 192.747
–	CL-7	Inspect, Test, and Maintain Programmable Logic Controllers, 49 CFR 192.605B, 10(iii), 192.739
✓	CM-1	Perform Patrol and Leakage Surveys on Gas Pipeline Facilities, 49 CFR 192.5, 192.613, 192.705, 192.706, 192.721, 192.723
✓	CM-2	Locate and Mark Underground Facilities, 49 CFR 192.614, 192.707
✓	CM-3	Pressure Testing Gas Pipelines, 49 CFR 192.503, 192.505, 192.507, 192.509, 192.511, 192.513, 192.725
✓	CM-4	Inspect and Test Pressure Limiting Stations, Relief Devices, and Pressure Regulating Devices, 49 CFR 192.201, 192.731, 192.739, 192.743, 192.749, 192.751
✓	CM-5	Inspect, Service, and Operate Line Valves, 49 CFR 192.179, 192.181, 192.745, 192.747
✓	CM-5a	Inspect Emergency Valves, 49 CFR 192.745, 192.747, 192.803
✓	CM-5b	Valve Corrective Maintenance, 49 CFR 192.747
	CM-6	Monitor Compressor Station Gas Leak Detection Equipment, 49 CFR 192.735, 192.736
✓	CM-7	Prevent Accidental Ignition, 49 CFR 192.751
✓	CM-8	Make Field Repairs on Gas Pipelines, 49 CFR 192.245, 192.307, 192.309, 192.311, 192.703, 192.711, 192.713, 192.715, 192.717
–	CM-9	Repair and Protect Cast Iron Pipe, 49 CFR 192.275, 192.489, 192.753, 192.755
✓	CM-10	Abandon or Deactivate Gas Pipeline Facilities, 49 CFR 192.727
✓	CM-11	Recognize and React to Generic Abnormal Operating Conditions, 49 CFR 192.751
✓	CM-12	Launch and Receive Pipeline Pigs, 49 CFR 192.150
–	CM-13	Investigate Reported Gas Leaks and Odors in Buildings
✓	CM-14	Inspect Vault Conditions, 49 cFR 192.749, 192.751
–	CM-15	Operate and Maintain Compressor Station Components, 49 CFR 192.167, 192.169, 192.171, 192.173, 192.199, 192.201, 192.605(a)(b)(6)(7), 192.731, 192.743

✓	CM-16	Inspect, Test, and Maintain Sensing Devices, 49 CFR 192.739, 192.741, 192.743
—	CM-17	Squeeze-Off Steel Pipe, 49 CFR 192.615
✓	CM-18	Station Emergency Shut Down System: Inspection, Testing, and Corrective Maintenance, 49 CFR 192.167, 192.171, 192.731, 192.736
✓	CM-19	Installing and Maintaining Customer Pressure Regulating, Pressure Limiting, and Pressure Relief Devices: Large Commercial and Industrial, 49 CFR 192.199, 192.743
✓	CM-20	Reciprocating Compressor Inspection, Testing, and Corrective Maintenance, 49 CFR 192.731
✓	CM-23	Measure and Characterize Mechanical Damage on Installed Pipe and Components, 49 CFR 192.307, 192.309
✓	CO-1	Conduct Indirect Pipe Inspections, 49 CFR 192.925, 192.947
✓	CO-2	Conduct Direct Pipe Examinations, 49 CFR 192.927, 192.947

Approved by:

Signature	Title	Date
Daryl L. Knight	PRESIDENT	5/18/16

DARRYL Knight
05/05/2016
ADD to OQmanual

UTI OQ Task Information

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Knight, Darryl L. **3Z03-1913CE-54**

ITS Task #	Qualifier	Evaluation Date	Expiration Date	*Qualification Method	Notes	*Veriforce Task Company (If applicable-NISourceTrans/Dominion)
CI-1	Linda Kuhlman	4/16/2015	4/16/2018	E, O	Pass	
CI-10	Linda Kuhlman	4/23/2015	4/23/2018	E, O	Pass	
CI-11	Linda Kuhlman	4/15/2015	4/15/2018	E, O	Pass	
CI-2	Linda Kuhlman	4/21/2015	4/21/2018	E, O	Pass	
CI-3	Linda Kuhlman	4/22/2015	4/22/2018	E, O	Pass	
CI-4	Linda Kuhlman	4/23/2015	4/23/2018	E, O	Pass	
CI-6	Linda Kuhlman	4/23/2015	4/23/2018	E, O	Pass	
CI-7	Linda Kuhlman	4/23/2015	4/23/2018	E, O	Pass	
CI-8	Linda Kuhlman	4/23/2015	4/23/2018	E, O	Pass	
CI-9	Linda Kuhlman	4/23/2015	4/23/2018	E, O	Pass	
F-1_F-2	Jack Lurty	5/11/2015	5/10/2016	E, O	Pass	
F-1_Other					Saddle 5/11/15	
F-2	Jack Lurty	5/11/2015	5/10/2016	E, O		
G-1	Linda Kuhlman	4/14/2015	4/14/2018	E, O	Pass	
H-1	Linda Kuhlman	4/22/2015	4/22/2018	E, O	Pass	
H-2	Linda Kuhlman	4/14/2015	4/14/2018	E, O	Pass	
L-3	Linda Kuhlman	4/22/2015	4/22/2018	E, O	Pass	
M-1	Linda Kuhlman	4/22/2015	4/22/2018	E, O	Pass	
M-10	Linda Kuhlman	4/15/2015	4/15/2018	E, O	Pass	
M-2	Linda Kuhlman	4/21/2015	4/21/2018	E, O	Pass	
M-3	Linda Kuhlman	4/14/2015	4/14/2018	E, O	Pass	
M-4	Linda Kuhlman	4/21/2015	4/21/2018	E, O	Pass	
M-5	Linda Kuhlman	4/21/2015	4/21/2018	E, O	Pass	
M-7FR	Linda Kuhlman	4/15/2015	4/15/2018	E	Pass	
M-8	Linda Kuhlman	4/15/2015	4/15/2018	E, O	Pass	
NI_L-1(c)	Jack Lurty	5/11/2015	5/11/2018	E, O	Pass	
NI_L-2NoR	Linda Kuhlman	4/14/2015	4/14/2018	E, O	Pass	

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Lette, Tyler E. **TW88-1B305F-83**

ITS Task #	Qualifier	Evaluation Date	Expiration Date	*Qualification Method	Notes	*Veriforce Task Company (If applicable-NISourceTrans/Dominion)
CF-1	Jeff Wolfe	4/27/2016	4/27/2017	E, O		
CF-2	Jeff Wolfe	4/27/2016	4/27/2017	E, O		
CF-6	Jeff Wolfe	4/28/2016	4/28/2019	E, O	Pass	ITS Compliance
CF-7	Jeff Wolfe	4/27/2016	4/27/2019	E, O	Pass	ITS Compliance
CL-1a	Jeff Wolfe	4/28/2016	4/28/2019	E, O	Pass	ITS Compliance

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McCormick, Jack **D552-2701A2-33**

ITS Task #	Qualifier	Evaluation Date	Expiration Date	*Qualification Method	Notes	*Veriforce Task Company (If applicable- NiSourceTrans/Dominion)
CF-1	Jeff Wolfe	4/27/2016	4/27/2017	E, O		
CF-2	Jeff Wolfe	4/27/2016	4/27/2017	E, O		
CI-1	Linda Kuhlman	4/16/2015	4/16/2018	E, O	Pass	
CI-11	Linda Kuhlman	4/15/2015	4/15/2018	E, O	Pass	
F-1_F-2	Jack Lurty	5/11/2015	5/10/2016	E, O	Pass	
F-1_Other					Saddle 5/11/15	
F-2	Jack Lurty	5/11/2015	5/10/2016	E, O		
G-1	Linda Kuhlman	4/14/2015	4/14/2018	E, O	Pass	
H-2	Linda Kuhlman	4/14/2015	4/14/2018	E, O	Pass	
M-10	Linda Kuhlman	4/15/2015	4/15/2018	E, O	Pass	
M-3	Linda Kuhlman	4/14/2015	4/14/2018	E, O	Pass	
M-7FR	Linda Kuhlman	4/15/2015	4/15/2018	E	Pass	
M-8	Linda Kuhlman	4/15/2015	4/15/2018	E, O	Pass	
Ni_L-1(c)	Jack Lurty	5/11/2015	5/11/2018	E, O	Pass	
Ni_L-2NoR	Linda Kuhlman	4/14/2015	4/14/2018	E, O	Pass	
CF-6	Jeff Wolfe	4/28/2016	4/28/2019	E, O	Pass	ITS Compliance
CF-7	Jeff Wolfe	4/27/2016	4/27/2019	E, O	Pass	ITS Compliance
CG-2	Ted Ressler	3/17/2016	3/17/2019	E, O	Pass	ITS Compliance
CL-1a	Jeff Wolfe	4/28/2016	4/28/2019	E, O	Pass	ITS Compliance

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McCormick, Ryan ZG37-23A060-66

ITS Task #	Qualifier	Evaluation Date	Expiration Date	*Qualification Method	Notes	*Veriforce Task Company (If applicable- NiSourceTrans/Dominion)
CF-1	Jeff Wolfe	4/27/2016	4/27/2017	E, O		
CF-2	Jeff Wolfe	4/27/2016	4/27/2017	E, O		
CI-1	Linda Kuhlman	4/16/2015	4/16/2018	E, O	Pass	
F-1_F-2	Jack Lurty	5/11/2015	5/10/2016	E, O	Pass	
F-1_Other					Saddle 5/11/15	
F-2	Jack Lurty	5/11/2015	5/10/2016	E, O		
G-1	Linda Kuhlman	4/14/2015	4/14/2018	E, O	Pass	
H-2	Linda Kuhlman	4/14/2015	4/14/2018	E, O	Pass	
M-3	Linda Kuhlman	4/14/2015	4/14/2018	E, O	Pass	
M-7FR	Linda Kuhlman	4/15/2015	4/15/2018	E	Pass	
Ni_L-1(c)	Jack Lurty	5/11/2015	5/11/2018	E, O	Pass	
Ni_L-2NoR	Linda Kuhlman	4/14/2015	4/14/2018	E, O	Pass	
CF-6	Jeff Wolfe	4/28/2016	4/28/2019	E, O	Pass	ITS Compliance
CF-7	Jeff Wolfe	4/27/2016	4/27/2019	E, O	Pass	ITS Compliance
CG-2	Ted Ressler	3/17/2016	3/17/2019	E, O	Pass	ITS Compliance
CL-1a	Jeff Wolfe	4/28/2016	4/28/2019	E, O	Pass	ITS Compliance

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Papp, George M. **7096-08C12F-08**

ITS Task #	Qualifier	Evaluation Date	Expiration Date	*Qualification Method	Notes	*Veriforce Task Company (If applicable-NISourceTrans/Dominion)
CF-1	Jeff Wolfe	4/27/2016	4/27/2017	E, O		
CF-2	Jeff Wolfe	4/27/2016	4/27/2017	E, O		
CF-6	Jeff Wolfe	4/28/2016	4/28/2019	E, O	Pass	ITS Compliance
CF-7	Jeff Wolfe	4/27/2016	4/27/2019	E, O	Pass	ITS Compliance
CG-2	Ted Ressler	3/17/2016	3/17/2019	E, O	Pass	ITS Compliance
CL-1a	Jeff Wolfe	4/28/2016	4/28/2019	E, O	Pass	ITS Compliance

UTI **OQ Task Information**

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Stanish, David **Jr. M257-24726C-18**

ITS Task #	Qualifier	Evaluation Date	Expiration Date	*Qualification Method	Notes	*Veriforce Task Company (If applicable-NiSourceTrans/Dominion)
CF-1	Jeff Wolfe	4/27/2016	4/27/2017	E, O		
CF-2	Jeff Wolfe	4/27/2016	4/27/2017	E, O		
CI-1	Linda Kuhlman	4/16/2015	4/16/2018	E, O	Pass	
CI-10	Linda Kuhlman	4/23/2015	4/23/2018	E, O	Pass	
CI-11	Linda Kuhlman	4/15/2015	4/15/2018	E, O	Pass	
CI-12	Linda Kuhlman	4/16/2015	4/16/2018	E, O	Pass	
CI-2	Linda Kuhlman	4/21/2015	4/21/2018	E, O	Pass	
CI-3	Linda Kuhlman	4/22/2015	4/22/2018	E, O	Pass	
CI-4	Linda Kuhlman	4/23/2015	4/23/2018	E, O	Pass	
CI-6	Linda Kuhlman	4/23/2015	4/23/2018	E, O	Pass	
CI-7	Linda Kuhlman	4/23/2015	4/23/2018	E, O	Pass	
CI-8	Linda Kuhlman	4/23/2015	4/23/2018	E, O	Pass	
CI-9	Linda Kuhlman	4/23/2015	4/23/2018	E, O	Pass	
F-1_F-2	Jack Lurty	5/11/2015	5/10/2016	E, O	Pass	
F-1_Other					Saddle 5/11/15	
F-2	Jack Lurty	5/11/2015	5/10/2016	E, O		
G-1	Linda Kuhlman	4/14/2015	4/14/2018	E, O	Pass	
H-1	Linda Kuhlman	4/22/2015	4/22/2018	E, O	Pass	
H-2	Linda Kuhlman	4/14/2015	4/14/2018	E, O	Pass	
L-3	Linda Kuhlman	4/22/2015	4/22/2018	E, O	Pass	
M-1	Linda Kuhlman	4/22/2015	4/22/2018	E, O	Pass	
M-10	Linda Kuhlman	4/15/2015	4/15/2018	E, O	Pass	
M-2	Linda Kuhlman	4/21/2015	4/21/2018	E, O	Pass	
M-3	Linda Kuhlman	4/14/2015	4/14/2018	E, O	Pass	
M-4	Linda Kuhlman	4/21/2015	4/21/2018	E, O	Pass	
M-5	Linda Kuhlman	4/21/2015	4/21/2018	E, O	Pass	
M-7FR	Linda Kuhlman	4/15/2015	4/15/2018	E	Pass	
M-8	Linda Kuhlman	4/15/2015	4/15/2018	E, O	Pass	
Ni_L-1(c)	Jack Lurty	5/11/2015	5/11/2018	E, O	Pass	
Ni_L-2NoR	Linda Kuhlman	4/14/2015	4/14/2018	E, O	Pass	
CF-6	Jeff Wolfe	4/28/2016	4/28/2019	E, O	Pass	ITS Compliance
CF-7	Jeff Wolfe	4/27/2016	4/27/2019	E, O	Pass	ITS Compliance
CL-1a	Jeff Wolfe	4/28/2016	4/28/2019	E, O	Pass	ITS Compliance

OQ Task Information

Utility Technologies International, Corporation 4700 Homer Ohio Lane, Groveport, OH 43125 614-482-8080

Ohio Rural Natural Gas Co-Op

7001 Center Street
Mentor, OH 44060 440-255-5198

***E = Exam, O = Observation by Simulation (No Observation on M-7 required)**
Prefixes of "NI_" are NiSource-specific modules, suffixes of "Propane" are propane modules
***Task Criteria = Criteria Established by Specific Veriforce Contractor Criteria**

Papp, Gregory **XH96-222097-72**

ITS Task #	Qualifier	Evaluation Date	Expiration Date	*Qualification Method	Notes	*Veriforce Task Company (If applicable- NiSourceTrans/Dominion)
CG-2	Ted Ressler	3/17/2016	3/17/2019	E, O	Pass	iTS Compliance

Ohio Rural Natural Gas Co-Op

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OQ TEST SCORE CONFIRMATION LETTER

Employer Confirmation of Student(s)'s Abilities to do the tasks listed below

		Module	Date	Evaluator	Method	Score	Circle YES if OK to do Task
Lette, Tyler E.	TW88-1B305F-83	CG-3	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CG-4	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CG-5	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-1	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-2	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-3	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-4	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-6	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CL-2	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
McCormick, Ryan	ZG37-23A060-66	CG-3	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CG-4	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CG-5	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-2	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-3	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-4	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-6	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
Papp, George M.	7096-08C12F-08	CG-3	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CG-4	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CG-5	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-1	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-2	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-3	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-4	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-6	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CL-2	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
Sebring, Ed K.	6071-2D31E8-44	CG-3	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CG-4	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CG-5	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-1	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-2	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-3	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-4	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-6	6/14/2016	Ted Ressler	E, O	Pass	Yes or No
		CL-2	6/14/2016	Ted Ressler	E, O	Pass	Yes or No

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OQ TEST SCORE CONFIRMATION LETTER

Employer Confirmation of Student(s)'s Abilities to do the tasks listed below

Module	Date	Evaluator	Method	Score	Circle YES if OK to do Task

Please review and authorize the above test scores for your employee(s) so certificates may be issued.
This form indicates that the necessary Knowledge and Skills have been evaluated by UTI
UTI is requesting your confirmation of the Student Ability to perform the job on site.

Please mark either Y (yes) or N (no) for each person and each task.
FAX: 614-482-8070
OR
MAIL: Utility Technologies International
4700 Homer Ohio Lane
Groveport, OH 43125

Please check SPELLING of names and company names for printing of certificates and cards.

Having knowledge of these person's training, work experience, job performance and the qualification test results shown above, I authorize UTI to issue a qualification certificate for the tasks as indicated. Failure to return this form in a timely manner could result in the certification being placed on hold.

Authorized Signature: Darryl L Knight

Print Name: DARRYL L. KNIGHT

Date: 6/30/16

List of Test Modules:

F1F2 - Fusion and Mechanical Joining
F2 - Mechanical Joining of Polyethylene Pipe
G1 - Excavation Backfilling
H1 - Install meter regulator sets
H2 - Install service lines
I-1 - Controlling Corrosion: Installing Test Leads Elec. Isolation, Monitoring Atmospheric Corrosion, Attach Anodes, Apply/Repair Coatings
I-1(1-4)-Monitoring Corrosion-Electrical Methods
I-1(5-8)-Monitoring Corrosion-Inspecting Rectifiers/Bonds
I-1(a) - Evaluation and Application of Corrosion Control
I-1(b) - Reading Test Stations, Eval. App. of Above Ground Corrosion Control
I-1(c) - Evaluation and Application of Above Ground Corrosion Control
I-1(d) - Monitoring Corrosion Control
L-1/L-1(a) - Tapping and Bagging Pipelines
L-1(b) - Tapping Pipelines
L-1(c) - Tapping Pipeline w. Self Tapping Tees
L2/L2(S) - Purge Gas Lines /Small
L-2(a) - Purge Service Lines
L-3 - Establish/ Maintain Odorant
L-3(s)- Monitor Odorant Levels

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OQ TEST SCORE CONFIRMATION LETTER

Employer Confirmation of Student(s)'s Abilities to do the tasks listed below

		Module	Date	Evaluator	Method	Score	Circle YES if OK to do Task
Lette, Tyler E.	TW88-1B305F-83	CG-1	6/13/2016	Ted Ressler	E, O	Pass	Yes or No
		CH-1	6/13/2016	Ted Ressler	E, O	Pass	Yes or No
		CH-2	6/13/2016	Ted Ressler	E, O	Pass	Yes or No
		CH-3	6/13/2016	Ted Ressler	E, O	Pass	Yes or No
		CH-4	6/13/2016	Ted Ressler	E, O	Pass	Yes or No
		CH-5	6/13/2016	Ted Ressler	E, O	Pass	Yes or No
		CM-3	6/13/2016	Ted Ressler	E, O	Pass	Yes or No
		M-7FR	6/13/2016	Ted Ressler	E	Pass	Yes or No
McCormick, Ryan	ZG37-23A060-66	CG-1	6/13/2016	Ted Ressler	E, O	Pass	Yes or No
		CH-1	6/13/2016	Ted Ressler	E, O	Pass	Yes or No
		CH-3	6/13/2016	Ted Ressler	E, O	Pass	Yes or No
		CH-4	6/13/2016	Ted Ressler	E, O	Pass	Yes or No
		CH-5	6/13/2016	Ted Ressler	E, O	Pass	Yes or No
Papp, George M.	7096-08C12F-08	CG-1	6/13/2016	Ted Ressler	E, O	Pass	Yes or No
		CH-1	6/13/2016	Ted Ressler	E, O	Pass	Yes or No
		CH-2	6/13/2016	Ted Ressler	E, O	Pass	Yes or No
		CH-3	6/13/2016	Ted Ressler	E, O	Pass	Yes or No
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		M-7FR	6/13/2016	Ted Ressler	E	Pass	Yes or No
Sebring, Ed K.	6071-2D31E8-44	CG-1	6/13/2016	Ted Ressler	E, O	Pass	Yes or No
		CH-1	6/13/2016	Ted Ressler	E, O	Pass	Yes or No
		CH-2	6/13/2016	Ted Ressler	E, O	Pass	Yes or No
		CH-3	6/13/2016	Ted Ressler	E, O	Pass	Yes or No
		CH-4	6/13/2016	Ted Ressler	E, O	Pass	Yes or No
		CH-5	6/13/2016	Ted Ressler	E, O	Pass	Yes or No
		CM-3	6/13/2016	Ted Ressler	E, O	Pass	Yes or No
		M-7FR	6/13/2016	Ted Ressler	E	Pass	Yes or No

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OQ TEST SCORE CONFIRMATION LETTER

Employer Confirmation of Student(s)'s Abilities to do the tasks listed below

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Please review and authorize the above test scores for your employee(s) so certificates may be issued. This form indicates that the necessary Knowledge and Skills have been evaluated by UTI UTI is requesting your confirmation of the Student Ability to perform the job on site.

Please mark either Y (yes) or N (no) for each person and each task.
FAX: 614-482-8070
OR
MAIL: Utility Technologies International
4700 Homer Ohio Lane
Groveport, OH 43125

Please check SPELLING of names and company names for printing of certificates and cards.

Having knowledge of these person's training, work experience, job performance and the qualification test results shown above, I authorize UTI to issue a qualification certificate for the tasks as indicated. Failure to return this form in a timely manner could result in the certification being placed on hold.

Authorized Signature: Darryl L. Knight

Print Name: DARRYL L. KNIGHT

Date: 6/30/16

List of Test Modules:

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F2 - Mechanical Joining of Polyethylene Pipe
G1 - Excavation Backfilling
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I-1 - Controlling Corrosion: Installing Test Leads Elec. Isolation, Monitoring Atmospheric Corrosion, Attach Anodes, Apply/Repair Coatings
I-1(1-4)-Monitoring Corrosion-Electrical Methods
I-1(5-8)-Monitoring Corrosion-Inspecting Rectifiers/Bonds
I-1(a) - Evaluation and Application of Corrosion Control
I-1(b) - Reading Test Stations, Eval. App. of Above Ground Corrosion Control
I-1(c) - Evaluation and Application of Above Ground Corrosion Control
I-1(d) - Monitoring Corrosion Control
L-1/L-1(a) - Tapping and Bagging Pipelines
L-1(b) - Tapping Pipelines
L-1(c) - Tapping Pipeline w. Self Tapping Tees
L2/L2(S) - Purge Gas Lines /Small
L-2(a) - Purge Service Lines
L-3 - Establish/ Maintain Odorant
L-3(s)- Monitor Odorant Levels

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OQ TEST SCORE CONFIRMATION LETTER

Employer Confirmation of Student(s)'s Abilities to do the tasks listed below

		Module	Date	Evaluator	Method	Score	Circle YES if OK to do Task
Courtney, Robert A.	GZ21-015294-44	CI-10	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-11	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-12	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-13	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-7	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-8	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-9	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
Lette, Tyler E.	TW88-1B305F-83	CI-10	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-11	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-12	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-13	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-7	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-8	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-9	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
McCormick, Ryan	ZG37-23A060-66	CI-10	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-11	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-12	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-13	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-7	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-8	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-9	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
Papp, George M.	7096-08C12F-08	CI-10	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-11	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-12	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-13	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-7	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-8	6/20/2016	Ted Ressler	E, O	Pass	Yes or No
		CI-9	6/20/2016	Ted Ressler	E, O	Pass	Yes or No