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ARKANSAS
PUBLIC SERVICE COMMISSION
UTILITIES DIVISION
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John P. Bethel
Director
(501) 682-1794

February 15, 2012

Ms. Jan Sanders
Secretary of the Arkansas Public Service Commission
1000 Center Street
Little Rock, AR 72201

RE: DOCKET NO. 11-166-R

Dear Ms. Sanders:

Please find attached an errata filing to supersede the document originally filed in this Docket as Attachment A to the Petition to Initiate a Docket for Rulemaking, which was also sponsored and incorporated into the testimony of Mr. Robert E. Henry on November 30, 2011.

By way of reference, this errata is being filed to correct the following typographical errors:

- Section 192.3 is corrected to include “kPa” in the definition of “Petroleum Gas”;
- Section 192.620(d)(3)(ii) is corrected to change “maintain” to “mainline”;
- Section 192.620(d)(7)(iv) is corrected to change “segment sin” to “segments in”; and
- Section 192.620(d)(7)(iv)(A) is corrected to change “associated” to “association”.

If you have any questions, please do not hesitate to contact me.

Regards,

/s/ John T. Elkins

Enclosure

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE REVISIONS TO	**)**	
THE ARKANSAS GAS PIPELINE CODE	**)**	**DOCKET NO. 11-166-R**

ERRATA ATTACHMENT A
FOR THE PETITION TO INTIATE A DOCKET FOR RULEMAKING

FEBRUARY 15, 2012

STAFF'S PROPOSED CHANGES TO THE ARKANSAS GAS PIPELINE CODE

As the result of the need to adopt U.S. Department of Transportation changes to the Pipeline Safety Regulations, 49 CFR Parts 191, 192, 193 and 199, and the need to conform Arkansas regulations to federal law, Staff recommends the following amendments to Part 191, 192, 193 and 199 of the Arkansas Gas Pipeline Code (Code). These changes are listed in sequential order of the code citation with annotations for the origin of the change.

Part 190 – Enforcement Procedures

Section 190.1 "(Commission)" is added after Arkansas Public Service Commission.[1]

Section 190.9(b) is amended by adding the word "Office" after "Pipeline Safety" [1]

Section 190.9(d) is revised by replacing "Pipeline Safety, Arkansas Public Service Commission" with "Pipeline Safety Office (PSO)", by inserting the text "by certified mail, return receipt requested" after "a written recommendation" in the first sentence, and replacing "Pipeline Safety" with "PSO" in the second sentence.[1]

Section 190.15(b) is revised by replacing "Arkansas Public Service Commission's" with "Commission's". [1]

Section 190.15(c) is revised by replacing Commission Staff" with "PSO". [1]

Section 190.23 is revised by inserting "Commission" before "Staff".[1]

Part 191 – Reports: Incident and Annual

Section 191.1 is revised by replacing "Arkansas Public Service Commission" with "PSO", and inserting the text "of this subchapter" after "192.8". [1,3]

Section 191.5 is revised to read as follows: [1,3]

§ 191.5 Telephonic Notice of Certain Incidents.

(a) At the earliest practicable moment following discovery, each operator shall give notice in accordance with paragraph (b) of this section of any natural gas incident involving a release of gas from a pipeline, or of liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:

(1) A death or personal injury requiring in-patient hospitalization; or

(2) Estimated property damage of $50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost; or

(3) Unintentional estimated gas loss of three million cubic feet or more;

(4) An event that results in an emergency shutdown of an LNG facility. Activation of an emergency shutdown system for reasons other than an actual emergency does not constitute an incident.

(5) An event that is significant, in the judgment of the operator, even though it did not meet the criteria of subparagraphs (1), (2), (3) or (4).

Incidents reportable under Subparagraphs (1), (2), (3), (4) or (5) above, include incidents occurring on all pipelines up to the outlet side of the customer's meter and must be reported at the earliest practicable moment unless there is evidence that the leak probably did not occur on pipelines used by the operator in the transportation of gas, in which case, notice may be delayed until determination is made.

(b) Each notice required by paragraph (a) of this section must be made to the National Response Center either by telephone to 800-424-8802 (in Washington, DC, 202-267-2675) or electronically at *http://www.nrc.uscg.mil* and must include the following information:

(1) Names of operator and person making report and their telephone numbers.

(2) The location of the incident.

(3) The time of the incident.

(4) The number of fatalities and personal injuries, if any.

(5) All other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages.

(c) In addition to the telephonic notice required in paragraph (b) of this section, notice will also be made by telephone to (501) 682-5716 during normal business hours Monday through Friday. Reports outside normal hours will be made to PSO personnel in accordance with instructions issued by the PSO.

(d) In addition to the requirements of paragraph (a) of this section, all gas related incidents which result in personal injury requiring out-patient treatment and/or property damage, including cost of lost gas, totaling $5,000 but less than $50,000, shall be telephonically reported to the Commission as required by paragraph (c) above.

<u>Section 191.7(a) is amended by adding “Office” after “Pipeline Safety” and 191.7(b) is amended to add “the Information Resources Manager” before “PHP-10” and by adding “-0001” to the zip code “20590”.</u> [1,2]

<u>Section 191.9(c) is revised to read as follows:</u> [3]

§ 191.9 Distribution System: Incident Report.

* * * * *

(c) Master meter operators are not required to submit an incident report as required by this section.

Section 191.11(b) is revised to read as follows: [3]

§ 191.11 Distribution System: Annual Report.

* * * * *

(b) The annual report required by this section need not be submitted with respect to:

(1) Petroleum gas systems which serve fewer than 100 customers from a single source; or

(2) Master meter systems.

Section 191.12 is added to read as follows: [4]

§ 191.12 Distribution Systems: Mechanical Fitting Failure Reports.

Each mechanical fitting failure, as required by § 192.1009, must be submitted on a Mechanical Fitting Failure Report Form PHMSA F–7100.1–2. An operator must submit a mechanical fitting failure report for each mechanical fitting failure that occurs within a calendar year not later than March 15 of the following year (for example, all mechanical failure reports for calendar year 2011 must be submitted no later than March 15, 2012). Alternatively, an operator may elect to submit its reports throughout the year. In addition, an operator must also report this information to the State pipeline safety authority if a State has obtained regulatory authority over the operator's pipeline.

Section 191.15 is revised to read as follows: [3]

§ 191.15 Transmission Systems; Gathering Systems; and Liquefied Natural Gas Facilities: Incident Report.

(a) *Transmission or Gathering.* Each operator of a transmission system or a gathering system subject to the jurisdiction of the Commission, shall submit Department of Transportation Form PHMSA F7100.2 as soon as practicable but not more than 20 days after detection of an incident required to be reported under § 191.5(a) or (d).

(b) *LNG*. Each operator of a liquefied natural gas plant or facility must submit DOT Form PHMSA F 7100.3 as soon as practicable but not more than 20 days after detection of an incident required to be reported under § 191.5 of this part.

(c) *Supplemental Report.* When additional relevant information is obtained after the report is submitted under paragraph (a) of this section, the operator shall make supplementary reports as deemed necessary with a clear reference by date and subject to the original report.

Section 191.17 is revised to read as follows: [3]

§ 191.17 Transmission Systems; Gathering Systems; and Liquefied Natural Gas Facilities: Annual Report.

(a) *Transmission or Gathering.* Each operator of a transmission system or a gathering system subject to the jurisdiction of the Commission shall submit an annual report on Department of Transportation Form PHMSA F7100.2-1. This report must be submitted for the preceding calendar year, not later than February 15 of each year.

(b) *LNG.* Each operator of a liquefied natural gas facility must submit an annual report for that system on DOT Form PHSMA 7100.3-1. This report must be submitted each year, not later than February 15, for the preceding calendar year.

Section 191.19 is removed. [3]

Part 192 – Minimum Safety Standards

A new Section 192.3 was created by copying the Definitions section and adding definitions of Active Corrosion, Alarm, Control Room, Controller, Electrical Survey, Pipeline Environment, and Supervisory Control and Data Acquisition System to read as follows: [2,5,6]

§ 192.3 Definitions

* *

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

* *

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

* *

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

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

* *

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

* *

Petroleum gas means propane, propylene, butane, (normal butane or isobutanes), and butylene (including isomers), or mixtures composed predominantly of these gases, having a vapor pressure not exceeding 208 psi (1434 kPa) gage at 100 degrees F (38degrees C).

* *

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

* *

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

* *

<u>Section 192.7 is revised to read as follows:</u> [2,6,7,8]

§ 192.7 What documents are incorporated by reference partly or wholly in this part?

(a) Any documents or portions thereof incorporated by reference in this part are included in this part as though set out in full. When only a portion of a document is referenced, the remainder is not incorporated in this subpart.

(b) All incorporated materials are available for inspection in the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue, SE, Washington, DC 20590-0001or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202-741-6030 or go to:http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html. These materials have been approved for incorporation by reference by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. In addition, the incorporated materials are available from the respective organizations listed in paragraph (c)(1) of this section.

(c) The full titles of documents incorporated by reference, in whole or in part, are provided herein. The numbers in parentheses indicate applicable editions. For each incorporated document, citations of all affected sections are provided. Earlier editions of currently listed documents or editions of documents listed in previous editions of 49 CFR part 192 may be used for materials and components designed, manufactured, or installed in accordance with these earlier documents at the time they were listed. The user must refer to the appropriate previous edition of 49 CFR part 192 for a listing of the earlier listed editions or documents.

(1) *Incorporated by reference (IBR). List of Organizations and Addresses:*

A. Pipeline Research Council International, Inc. (PRCI), c/o Technical Toolboxes, 3801

Kirby Drive, Suite 520, Houston, TX 77098.

B. American Petroleum Institute (API), 1220 L Street, NW, Washington, DC 20005.

C. American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, West Conshohocken, PA 19428.

D. ASME International (ASME), Three Park Avenue, New York, NY 10016-5990.

E. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park Street NE, Vienna, VA 22180.

F. National Fire Protection Association (NFPA), 1 Batterymarch Park, P.O. Box 9101, Quincy, MA 02269-9101.

G. Plastics Pipe Institute, Inc. (PPI), 1825 Connecticut Avenue, NW, Suite 680, Washington, DC 20009.

H. NACE International (NACE), 1440 South Creek Drive, Houston, TX 77084.

I. Gas Technology Institute (GTI), 1700 South Mount Prospect Road, Des Plaines, IL 60018.

(2) *Documents incorporated by reference.*

Source and name of referenced material	49 CFR reference
A. Pipeline Research Council International (PRCI): (1) AGA Pipeline Research Committee, Project PR-3-805, “A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe,” (December 22, 1989). The RSTRENG Program may be used for calculating remaining strength.	§§ 192.485(c); 192.933(a)(1); 192.933(d)(1)(i).
B. American Petroleum Institute (API): (1) ANSI/API Specification 5L/ISO 3183 “Specification for Line Pipe” (44th edition, 2007), includes errata (January 2009) and	§§ 192.55(e); 192.112; 192.113; Item I, Appendix B to Part 192.

addendum (February 2009).	
(2) API Recommended Practice 5L1 "Recommended Practice for Railroad Transportation of Line Pipe," (6th edition, July 2002)	§ 192.65(a)(1).
(3) API Recommended Practice 5LW, "Transportation of Line Pipe on Barges and Marine Vessels" (2nd edition, December 1996, effective March 1, 1997).	§ 192.65(b).
(4) ANSI/API Specification 6D, "Specifications for Pipeline Valves" (23rd edition (April 2008, effective October 1, 2008) and errata 3 (includes 1 and 2, February 2009)).	§ 192.145(a).
(5) API Recommended Practice 80, "Guidelines for the Definition of Onshore Gas Gathering Lines," (1st edition, April 2000).	§§ 192.8(a); 192.8(a)(1); 192.8(a)(2); 192.8(a)(3); 192.8(a)(4).
(6) API Standard 1104, "Welding of Pipelines and Related Facilities" (20th edition, October 2005, errata/addendum, (July 2007) and errata 2 (2008)).	§§ 192.225; 192.227(a); 192.229 (c)(1); 192.241(c); Item II, Appendix B.
(7) API Recommended Practice 1162, "Public Awareness Programs for Pipeline Operators," (1st edition, December 2003).	§§ 192.616(a); 192.616(b); 192.616(c).
(8) API "Recommended Practice 1165 "Recommended Practice for Pipeline SCADA Displays," (API RP 1165)(First edition (January 2007)).	§ 192.631(c)(1).
C. American Society for Testing and Materials (ASTM):	
(1) ASTM A53/A53M-07 "Standard Specification for Pipe, Steel, Black and Hot - Dipped, Zinc-Coated, Welded and Seamless" (September 1, 2007).	§§ 192.113; Item I, Appendix B to Part 192.
(2) ASTM A106/A106M-08, "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service" (July 15, 2008).	§§ 192.113; Item I, Appendix B to Part 192.
(3) ASTM A333/A333M-05 (2005) "Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service".	§§ 192.113; Item I, Appendix B to Part 192.
(4) ASTM A372/A372M-03 (Reapproved 2008) "Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels" (March 1, 2008).	§192.177(b)(1).
(5) ASTM A381-96 (Reapproved 2005) "Standard Specification for Metal-Arc	§§192.113; Item I, Appendix B to Part 192.

Welded Steel Pipe For Use With High-Pressure Transmission Systems" (October 1, 2005).	
(6) ASTM Designation: A 578/A578M-96 (Re-approved 2001) "Standard Specification for Straight-Beam Ultrasonic Examination of Plain and Clad Steel Plates for Special Applications."	§§192.112(c)(2)(iii).
(7) ASTM A671-06 "Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures" (May 1, 2006).	§§ 192.113; Item I, Appendix B to Part 192.
8) ASTM A672-08 "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures" (May 1, 2008).	§§ 192.113; Item I, Appendix B to Part 192.
(9) ASTM A691-98 (Reapproved 2007) "Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures" (November 1, 2007).	§§ 192.113; Item I, Appendix B to Part 192.
(10) ASTM D638-03 "Standard Test Method for Tensile Properties of Plastics."	§§ 192.283(a)(3); 192.283(b)(1).
(11) ASTM D2513-87 "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings".	§ 192.63(a)(1).
(12) ASTM D2513-99 "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings".	§§192.123(e)(2); 192.192.191(b); 192.281(b)(2); 192.283(a)(1)(i); Item I, Appendix B to Part 192.
(13) ASTM D2517-00 "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings".	§§192.191(a); 192.281(d)(1); 192.283(a)(1)(ii); Item I, Appendix B to Part 192.
(14) ASTM F1055-1998 "Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controller Polyethylene Pipe And Tubing".	§192.283(a)(1)(iii).
D. ASME International (ASME):	
(1) ASME/ANSI B16.1-2005 "Gray Iron Pipe Flanges and Flanged Fittings: (Classes 25, 125, and 250." (August 31, 2006)..	§192.147(c).
(2) ASME/ANSI B16.5-2003 "Pipe Flanges and Flanged Fittings." (October 2004)	§§ 192.147(a); 192.279.
(3) ASME/ANSI B31G-1991 (Reaffirmed; 2004) "Manual for Determining the Remaining Strength of Corroded Pipelines".	§§ 192.485(c); 192.933(a).
(4) ASME/ANSI B31.8-2007 (February 2004)	§ 192.619(a)(1)(i).

"Gas Transmission and Distribution Piping Systems" (November 30, 2007).	
(5) ASME/ANSIB31.8S-2004 "Supplement to B31.8 on Managing System Integrity of Gas Pipelines".	§§ 192.903(c); 192.907(b); 192.911, Introductory text; 192.911(i); 192.911(k); 192.911(i); 192.911(m); 192.913(a) Introductory text; 192.913(b)(1); 192.917(a) Introductory text; 192.917(b); 192.917(c); 192.917(e)(1); 192.917(e)(4); 192.921(a)(1); 192.923(b)(2); 192.923(b)(3); 192.925(b) Introductory text; 192.925(b)(1); 192.925(b)(2); 192.925(b)(3); 192.925(b)(4);192.927(b); 192.927(c)(1)(i); 192.929(b)(1); 192.929(b)(2); 192.933(a); 192.933(d)(1); 192.933(d)(1)(i); 192.935(a); 192.935(b)(1)(iv); 192.937(c)(1); 192.939(a)(1)(i); 192.939(a)(1)(ii); 192.939(a)(3); 192.945(a).
(6) 2007 ASME Boiler and Pressure Vessel Code, Section I, "Rules for Construction of Power Boilers 2007," (2007 edition, July 1, 2007).	§192.153(b).
(7) 2007 ASME Boiler and Pressure Vessel Code, Section VIII, Division 1, "Rules for Construction of Pressure Vessels 2" (2007 edition, July 1, 2007).	§§ 192.153(a) 192.153(b); 192.153(d); 192.165(b)(3).
(8) 2007 ASME Boiler and Pressure Vessel Code, Section VIII, Division 2, "Alternative Rules, Rules for Construction of Pressure Vessels" (2007 edition, July 1, 2007).	§§ 192.153(b); 192.165(b)(3).
(9) 2007 ASME Boiler and Pressure Vessel Code, Section IX, "Welding and Brazing Procedures, Welders, Brazers, and Welding and Brazing Operators" (2007 edition, July 1, 2007).	§§ 192.227(a); Item II, Appendix B to Part 192.
E. Manufacturers Standardization Society of the Valve and Fitting Industry, Inc. (MSS):	
(1) MSS SP-44-2006, Standard Practice, "Steel Pipeline Flanges" (2006 edition)	§ 192.147(a).
(2) [Reserved]………………………………....	
F. National Fire Protection Association (NFPA):	
(1) NFPA 30 (2008 edition, August 15, 2007),) "Flammable and Combustible Liquids Code." (2008 edition; approved August 15, 2007)	§ 192.735(b).
(2) NFPA 58 (2004) "Liquefied Petroleum Gas	§§ 192.11(a); 192.11(b); 192.11(c).

Code (LP-Gas Code)."	
(3) NFPA 59 (2004) "Utility LP-Gas Plant Code."...	§§ 192.11(a); 192.11(b); 192.11(c).
(4) NFPA 70 (2008) "National Electrical Code" (NEC 2008) (Approved August 15, 2007).…	§§ 192.163(e); 192.189(c).
G. Plastics Pipe Institute, Inc. (PPI):	
(1) PPI TR-3/2008 HDB/HDS/PDB/SDB/MRS Policies (2008) "Policies and Procedures for Developing Hydrostatic Design Basis (HDB), Pressure Design Basis (PDB), Strength Design Basis (SDB), and Minimum Required Strength (MRS) Ratings for Thermoplastic Piping Materials or Pipe" (May 2008).	§ 192.121.
H. NACE International (NACE):	
(1) NACE Standard RP0502-2008, Standard Practice, "Pipeline External Corrosion Direct Assessment Methodology" (reaffirmed March 2008).	§§ 192.923(b)(1); 192.925(b) Introductory text; 192.925(b)(1); 192.925(b)(1)(ii); 192.925(b)(2) Introductory text; 192.925(b)(3) Introductory text; 192.925(b)(3)(ii); 192.925(b)(3)(iv); 192.925(b)(4) Introductory text; 192.925(b)(4)(ii); 192.931(d); 192.935(b)(1)(iv); 192.939(a)(2).
I. Gas Technology Institute (GTI):	
(1) GRI 02/0057 (2002) "Internal Corrosion Direct Assessment of Gas Transmission Pipelines Methodology".	§ 192.927(c)(2).

Section 192.63(a)(1) is revised to read as follows: [6]

§ 192.63 Marking of Materials.

(a) Except as provided in paragraph (d) of this section, each valve, fitting, length of pipe, and other component must be marked:

(1) As prescribed in the specification or standard to which it was manufactured, except that thermoplastic fittings must be marked in accordance with ASTM D2513—87 (incorporated by reference, *see* § 192.7); and

Section 192.65 is revised to read as follows: [6]

§ 192.65 Transportation of Pipe.

(a) *Railroad*. In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by railroad unless:

(1) The transportation is performed in accordance with API Recommended Practice 5L1 (incorporated by reference, *see* § 192.7).

(2) In the case of pipe transported before November 12, 1970, the pipe is tested in accordance with Subpart J of this Part to at least 1.25 times the maximum allowable operating pressure if it is to be installed in a class 1 location and to at least 1.5 times the maximum allowable operating pressure if it is to be installed in a class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under Subpart J of this Part, the test pressure must be maintained for at least 8 hours.

(b) *Ship or barge.* In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by ship or barge on both inland and marine waterways unless the transportation is performed in accordance with API Recommended Practice 5LW (incorporated by reference, *see* § 192.7).

Add and revise Section 192.112 to subpart C to read as follows: [7,9]

§ 192.112 Additional Design 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 (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 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 Specific 5L, product specification level 2 (incorporated by reference, see § 192.7) for maximum operating pressures and minimum

(b) Fracture control	and maximum operating temperatures and other requirements under this section. (1) The toughness properties for pipe must address the potential for initiation, propagation and arrest of fractures in accordance with: (i) API specification 5L (incorporated by reference, see § 192.7); (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 Specification 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 pressure 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 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 the API Specification 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 the 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 Specification 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.
	(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

(f) Coating	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.

Section 192.121 is revised to read as follows: [6,9,10]

§ 192.121 Design of Plastic Pipe.

Subject to the limitations of § 192.123, the design pressure for plastic pipe is determined by either of the following formulas:

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

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

Where:

P = Design pressure, gauge, psig (kPa).

S = For thermoplastic pipe, the HDB is determined in accordance with the listed specification at a temperature equal to 73°F (23°C), 100°F (38°C), 120°F (49°C), or 140°F (60°C). In the absence of an HDB established at the specified temperature, the HDB of a higher temperature may be used in determining a design pressure rating at the specified temperature by arithmetic interpolation using the procedure in Part D.2 of PPI TR-3/2008, *HDB/PDB/SDB/MRS Policies* (incorporated by reference, see § 192.7). For reinforced thermosetting plastic pipe, 11,000 psig (75,842 kPa). [Note: Arithmetic interpolation is not allowed for PA-11 pipe.]

t = Specified wall thickness, inches (mm).
D = Specified outside diameter, inches (mm).
SDR = Standard dimension ratio, the ratio of the average specified outside diameter to the minimum specified wall thickness, corresponding to a value from a common numbering system that was derived from the American National Standards Institute preferred number series 10.
D F = 0.32 or
= 0.40 for PA-11 pipe produced after January 23, 2009 with a nominal pipe size (IPS or CTS) 4-inch or less, and a SDR or 11 or greater (i.e. thicker pipe wall).

Section 192.123 is revised to read as follows: [6,10]

§ 192.123 Design Limitations for Plastic Pipe.

(a) Except as provided in paragraph (e) and paragraph (f) of this section, the design pressure may not exceed a gauge pressure of 100 psig (689 kPa) for plastic pipe used in:
(1) Distribution systems; or
(2) Class 3 and 4 locations.

(b) Plastic pipe may not be used where operating temperature of the pipe will be:
(1) Below -20°F (-29°C); or below -40°F (-40°C) if all pipe and pipeline components whose operating temperature will be below -20°F (-29°C) have a temperature rating by the manufacturer consistent with that operating temperature; or
(2) Above the following applicable temperatures:
(i) For thermoplastic pipe, the temperature at which the HDB used in the design formula under § 192.121 is determined.
(ii) For reinforced thermosetting plastic pipe, 150ºF (66ºC).

(c) The wall thickness for thermoplastic pipe may not be less than 0.062 in. (1.57 millimeters).

(d) The wall thickness for reinforced thermosetting plastic pipe may not be less than that listed in the following table:

Nominal size in inches (millimeters)	Minimum wall thickness inches (millimeters)
2 (51)	0.060 (1.52)
3 (76)	0.060 (1.52)
4 (102)	0.070 (1.78)
6 (152)	0.100 (2.54)

(e) The design pressure for thermoplastic pipe produced after July 14, 2004 may exceed a gauge pressure of 100 psig (689 kPa) provided that:
(1) The design pressure does not exceed 125 psig (862 kPa);

(2) The material is a PE2406 or a PE3408 as specified within ASTM D2513-99 (incorporated by reference, *see* § 192.7);
(3) The pipe size is nominal pipe size (IPS) 12 or less; and
(4) The design pressure is determined in accordance with the design equation defined in §192.121.

(f) The design pressure for polyamide-11 (PA-11) pipe produced after January 23, 2009 may exceed a gauge pressure of 100 psig (689 kPa) provided that:
(1) The design pressure does not exceed 200 psig (1379 kPa);
(2) The pipe size is nominal pipe size (IPS or CTS) 4-inch or less; and
(3) The pipe has a standard dimension ratio of SDR-11 or greater (*i.e.,*thicker pipe wall).

<u>Section 192.145(d) and Section 192.145(e) are revised as follows:</u> [6]

§ 192.145 Valves.

* * * * *

(d) No valve having shell (Body, bonnet, cover, and/or end flange) components made of ductile iron may be used at pressures exceeding 80 percent of the pressure ratings for comparable steel valves at their listed temperature. However, a valve having shell components made of ductile iron may be used at pressures up to 80 percent of the pressure ratings for comparable steel valves at their listed temperature, if:

(1) The temperature-adjusted service pressure does not exceed 1,000 p.s.i. (7 MPa); and

(2) Welding is not used on any ductile iron component in the fabrication of the valve shells or their assembly.

(e) No valve having shell (body, bonnet, cover, and/or end flange) components made of cast iron, malleable iron, or ductile iron may be used in the gas pipe components of compressor stations.

<u>Section 192.191 is revised to read as follows:</u> [6]

§ 192.191 Design Pressure of Plastic Fittings.

(a) Thermosetting fittings for plastic pipe must conform to ASTM D 2517, (incorporated by reference, *see* § 192.7).

(b) Thermoplastic fittings for plastic pipe must conform to ASTM D 2513-99, (incorporated by reference, *see* § 192.7).

<u>Section192.281(a) and Section 192.281(b) are revised to read as follows:</u> [6]

§ 192.281 Plastic Pipe.

(a) *General.* A plastic pipe joint that is joined by solvent cement, adhesive, or heat fusion may not be disturbed until it has properly set. Plastic pipe may not be joined by a threaded joint or miter joint.

(b) *Solvent cement joints.* Each solvent cement joint on plastic pipe must comply with the following:

(1) The mating surfaces of the joint must be clean, dry, and free of material which might be detrimental to the joint.

(2) The solvent cement must conform to ASTM D2513-99, (incorporated by reference, *see* § 192.7).

(3) The joint may not be heated to accelerate the setting of the cement.

(4) Plastic pipe manufactured from different materials shall not be joined by solvent cement joints.

* * * * *

<u>Section 192.283(a) is revised to read as follows:</u> [6]

§ 192.283 Plastic Pipe: Qualifying Joining Procedures.

(a) *Heat Fusion, Solvent Cement, and Adhesive Joints.* Before any written procedure established under § 192.273(b) is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints made according to the procedure to the following tests:

(1) The burst test requirements of—

(i) In the case of thermoplastic pipe, paragraph 6.6 (sustained pressure test) or paragraph 6.7 (Minimum Hydrostatic Burst Test) or paragraph 8.9 (Sustained Static Pressure Test) of ASTM D2513—99 (incorporated by reference, *see* § 192.7);

(ii) In the case of thermosetting plastic pipe, paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Static Pressure Test) of ASTM D2517 (incorporated by reference, *see* § 192.7); or

(iii) In the case of electrofusion fittings for polyethylene (PE) pipe and tubing, paragraph 9.1 (Minimum Hydraulic Burst Pressure Test), paragraph 9.2 (Sustained Pressure Test), paragraph 9.3 (Tensile Strength Test), or paragraph 9.4 (Joint Integrity Tests) of ASTM Designation F1055 (incorporated by reference, *see* § 192.7).

(2) For procedures intended for lateral pipe connections, subject a specimen joint made from pipe sections joined at right angles according to the procedure to a force on the lateral pipe until failure occurs in the specimen. If failure initiates outside the joint area, the procedure qualifies for use; and

(3) For procedures intended for non-lateral pipe connections, follow the tensile test requirements of ASTM D638 (incorporated by reference, *see* § 192.7),

except that the test may be conducted at ambient temperature and humidity if the specimen elongates no less than 25 percent or failure initiates outside the joint area, the procedure qualifies for use.

Section 192.328 is added to subpart G to read as follows: [7]

§ 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.

Section 192.383 is revised to read as follows: [4,11,12]

§ 192.383 Excess Flow Valve Installation.

(a) Definitions. As used in this section:

Replaced service line means a gas service line where the fitting that connects the service line to the main is replaced or the piping connected to this fitting is replaced.

Service line serving single-family residence means a gas service line that begins at the fitting that connects the service line to the main and serves only one single family residence.

(b) *Installation required*. An excess flow valve (EFV) installation must comply with the performance standards in § 192.381. The operator must install an EFV on any new or replaced service line serving a single-family residence after February 12, 2010, unless one or more of the following conditions is present:

(1) The service line does not operate at a pressure of 10 psig or greater throughout the year;

(2) The operator has prior experience with contaminants in the gas stream that could interfere with the EFV's operation or cause loss of service to a residence;

(3) An EFV could interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or

(4) An EFV meeting performance standards in § 192.381 is not commercially available to the operator.

(c) *Reporting.* Each operator must report the EFV measures detailed in the annual report required by § 191.11.

Section 192.465 (e) is revised to read as follows: [6]

§ 192.465 External Corrosion Control: Monitoring.

* * * * *

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

Section 192.605(b)(12) is added to read as follows: [5]

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

Section 192.611(a) is revised to read as follows: [7]

§ 192.611 Change in class location: Confirmation or revision of maximum allowable operating pressure.

(a) * * *

(1) If the segment involved has been previously tested in place for a period of not less than 8 hours:

(i) The maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.
(ii) The alternative maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations and 0.667 times the test pressure in Class 3 locations. For pipelines operating at alternative maximum allowable pressure per § 192.620, the corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations

* * *

(3) * * *

(i) The maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations, 0.667 times the test pressure for Class 3 locations, and 0.555 times the test pressure for Class 4 locations.
(ii) The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.
(iii) For pipeline operating at an alternative maximum allowable operating pressure per § 192.620, the alternative maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations and 0.667 times the test pressure for Class 3 locations. The corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations

* * * * *

<u>Section 192.615(a) is revised to add a subsection to read as follows:</u> [5]

§ 192.615 Emergency Plans.

(a) * * *
* * *
(11) Actions required to be taken by a controller during an emergency in accordance with § 192.631.

<u>Section 192.619 amended by revising paragraph (a) introductory text and by adding paragraph (d) to read as follows:</u> [7]

§ 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:

* * * * *

(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).

<u>Section 192.620 is added to subpart L to read as follows:</u> [7,9]

§ 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 the 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 the 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 intrastate 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 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 are 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 alternate 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 remove 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 section. (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 the 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 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 tolerance of the tools used in 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 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.

Section 192.631 is added to Subpart L to read as follows: [5,13,14]

§ 192.631 Control Room Management.

(a) *General*

(1) This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section, except that for each control room where an operator's activities are limited to either or both of:

(i) Distribution with less than 250,000 services, or

(ii) Transmission without a compressor station, the operator must have and follow written procedures that implement only paragraphs (d) (regarding fatigue), (i) (regarding compliance validation), and (j) (regarding compliance and deviations) of this section.

(2) The procedures required by this section must be integrated, as appropriate, with operating and emergency procedures required by §§ 192.605 and 192.615. An operator must develop the procedures no later than August 1, 2011, and must implement the procedures according to the following schedule. The procedures required by paragraphs (b), (c)(5), (d)(2) and (d)(3), (f) and (g) of this section must be implemented no later than October 1, 2011. The procedures required by paragraphs (c)(1) through (4), (d)(1), (d)(4), and (e) must be implemented no later than August 1, 2012. The training procedures required by paragraph (h) must be implemented no later than August 1, 2012, except that any training required by another paragraph of this section must be implemented no later than the deadline for that paragraph.

(b) *Roles and responsibilities*. Each operator must define the roles and responsibilities of a controller during normal, abnormal, and emergency operating conditions. To provide for a controller's prompt and appropriate response to operating conditions, an operator must define each of the following:
   (1) A controller's authority and responsibility to make decisions and take actions during normal operations;
   (2) A controller's role when an abnormal operating condition is detected, even if the controller is not the first to detect the condition, including the controller's responsibility to take specific actions and to communicate with others;
   (3) A controller's role during an emergency, even if the controller is not the first to detect the emergency, including the controller's responsibility to take specific actions and to communicate with others; and
   (4) A method of recording controller shift-changes and any hand-over of responsibility between controllers.

(c) *Provide adequate information.* Each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following:
   (1) Implement sections 1, 4, 8, 9, 11.1, and 11.3 of API RP 1165 (incorporated by reference, see § 192.7) whenever a SCADA system is added, expanded or replaced, unless the operator demonstrates that certain provisions of sections 1, 4, 8, 9, 11.1, and 11.3 of API RP 1165 are not practical for the SCADA system used;
   (2) Conduct a point-to-point verification between SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays;
   (3) Test and verify an internal communication plan to provide adequate means for manual operation of the pipeline safely, at least once each calendar year, but at intervals not to exceed 15 months;
   (4) Test any backup SCADA systems at least once each calendar year, but at intervals not to exceed 15 months; and
   (5) Establish and implement procedures for when a different controller assumes responsibility, including the content of information to be exchanged.

(d) *Fatigue mitigation*. Each operator must implement the following methods to reduce the risk associated with controller fatigue that could inhibit a controller's ability to carry out the roles and responsibilities the operator has defined;
   (1) Establish shift lengths and schedule rotations that provide controllers off-duty time sufficient to achieve eight hours of continuous sleep;
   (2) Educate controllers and supervisors in fatigue mitigation strategies and how off-duty activities contribute to fatigue.
   (3) Train controllers and supervisors to recognize the effects of fatigue; and
   (4) Establish a maximum limit on controller hours-of-service, which may provide for an emergency deviation from the maximum limit if necessary for the safe operation of a pipeline facility.

(e) *Alarm management.* Each operator using a SCADA system must have a written alarm management plan to provide for effective controller response to alarms. An operator's plan must include provisions to:

(1) Review SCADA safety-related alarm operations using a process that ensures alarms are accurate and support safe pipeline operations.
(2) Identify at least once each calendar month points affecting safety that have been taken off scan in the SCADA host, have had alarms inhibited, generated false alarms, or that have had forced or manual values for periods of time exceeding that required for associated maintenance or operating activities;
(3) Verify the correct safety-related alarm set-point values and alarm descriptions at least once each calendar year, but at intervals not to exceed 15 months;
(4) Review the alarm management plan required by this paragraph at least once each calendar year, but at intervals not exceeding 15 months, to determine the effectiveness of the plan;
(5) Monitor the content and volume of general activity being directed to and required of each controller at least once each calendar year, but at intervals not to exceed 15 months, that will assure controllers have sufficient time to analyze and react to incoming alarms; and
(6) Address deficiencies identified through the implementation of paragraphs (e)(1) through (e)(5) of this section.

(f) *Change management*. Each operator must assure that changes that could affect control room operations are coordinated with the control room personnel by performing each of the following:
(1) Establish communications between control room representatives, operator's management, and associated field personnel when planning and implementing physical changes to pipeline equipment or configuration;
(2) Require its field personnel to contact the control room when emergency conditions exist and when making field changes that affect control room operations; and
(3) Seek control room or control room management participation in planning prior to implementation of significant pipeline hydraulic or configurations changes.

(g) *Operating experience.* Each operator must assure that lessons learned from its operating experience are incorporated, as appropriate, into its control room management procedures by performing each of the following:
(1) Review incidents that must be reported pursuant to 49 CFR part 191 to determine if control room actions contributed to the event and, if so, correct, where necessary, deficiencies related to:
(i) Controller fatigue;
(ii) Field equipment;
(iii) The operation of any relief device;
(iv) Procedures;
(v) SCADA system configuration; and
(vi) SCADA system performance.
(2) Include lessons learned from the operator's experience in the training program required by this section.

(h) *Training.* Each operator must establish a controller training program and review the training program content to identify potential improvements at least once each calendar year, but at intervals not to exceed 15 months. An operator's program must provide for training each controller to carry out the roles and responsibilities defined by the operator. In addition, the training program must include the following elements:

(1) Responding to abnormal operating conditions likely to occur simultaneously or in sequence;
(2) Use of a computerized simulator of non-computerized (tabletop) method for training controllers to recognize abnormal operating conditions;
(3) Training controllers on their responsibilities for communication under the operator's emergency response procedures;
(4) Training that will provide a controller a working knowledge of the pipeline system, especially during the development of abnormal operating conditions; and
(5) For pipeline operating setups that are periodically, but infrequently used, providing an opportunity for controllers to review relevant procedures in advance of their application.

(i) *Compliance validation.* Upon request, operators must submit their procedures to PHMSA or, in the case of an intrastate pipeline facility regulated by a State, to the appropriate State agency.

(j) *Compliance and deviation.* An operator must maintain for review during inspection:

(1) Records that demonstrate compliance with the requirements of this section; and
(2) Documentation to demonstrate that any deviation from the procedures required by this section was necessary for the safe operation of a pipeline facility.

<u>Section 192.711 is revised to read as follows: </u>[6]

§ 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.

Section 192.723(b)(2) and (g)(5) are revised to read as follows: [14,15,16]

§ 192.723 Distribution Systems: Leakage Surveys and Procedures.

* * * * *
(b) * * *

(2) A leakage survey with leak detector equipment must be conducted outside business districts as frequently as necessary, but at intervals not exceeding 5 calendar years not exceeding 63 months. However, for cathodically unprotected distribution lines subject to §192.465(e) on which electrical surveys for corrosion are impractical, a leakage survey must be conducted at least once every 3 calendar years at intervals not exceeding 39 months.
* * * * *
(g) * * *

(5) Unique identifier for person making the repair or responsible for maintaining the records of work accomplished.

Section 192.727, paragraph (g)(1) is amended by adding the words "Office of Pipeline Safety," before the words "Pipeline and Hazardous Materials Safety Administration," adding "Information Resources Manager," before "PHP-10"; and adding "-0001" to the zip code "20590".

In Sections 192.923, 192.925, 192.931, 192.935, and 192.939 the words "NACE RP0502-2002" are replaced by the words "NACE SP0502-2008" [6]

Section 192.945(a) is revised to read as follows: [3]

§ 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 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 of this part), 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 as part of the annual report required by § 191.17 of this subchapter.

Section 192.949 (a) is amended by moving the words "Information Resources Manager," from their current position and placing them before "PHP-10," and by adding "-0001" to the zip code "20590". [2]

Section 192.951 is revised to read as follows:[2,3]

§ 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 through the online reporting system provided by PHMSA for electronic reporting available at the PHMSA Home Page at http://phmsa.dot.gov.

In Part 192, a new subpart P is added to read as follows: [4,11]

SUBPART P – GAS DISTRIBUTION PIPELINE INTEGRITY MANAGEMENT (IM)

§ 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 probably 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.

Mechanical fitting means a mechanical device used to connect sections of pipe. The term “Mechanical fitting” applies only to:

(1) Stab Type fittings;

(2) Nut Follower Type fittings;

(3) Bolted Type fittings; or

(4) Other Compression Type fittings.

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 or welds, equipment failure, incorrect operations, 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 reevaluate 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 a mechanical fitting fails?

(a) Except as provided in paragraph (b) of this section, each operator of a distribution pipeline system must submit a report on each mechanical fitting failure, excluding any failure that results only in a nonhazardous leak, on a

Department of Transportation Form PHMSA F-7100.1-2. The report(s) must be submitted in accordance with § 191.12.

(b) The mechanical fitting failure reporting requirements in paragraph (a) of this section do not apply to the following:
   (1) Master meter operators;
   (2) Small LPG operator as defined in § 192.1001: or
   (3) LNG facilities.

§ 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:
   (2) *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).
   (3) *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.

(4) *Rank risks.* The operator must evaluate the risks to its pipeline and estimate the relative importance of each identified threat.

(5) *Identify and implement measures to mitigate risks.* The operator must determine and implement measures designed to reduce the risks from failure of its pipeline.

(6) *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.

(7) *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.

<u>Section I of Appendix B to Part 192, is revised by replacing the phrase "ASTM D2513" with "ASTM D2513-99".</u> [6]

<u>Section 193.2011 is revised to read as follows:</u> [3]

<u>Part 193 – Liquefied Natural Gas Facilities</u>

§ 193.2011 Reporting.

Incidents, safety-related conditions, and annual pipeline summary data for LNG plants or facilities must be reported in accordance with the requirements of Part 191 of this subchapter.

<u>Section 193.2013 is revised to read as follows:</u>[2,6]

§ 193.2013 Incorporation by reference.

(a) Any document or portion thereof incorporated by reference in this part is included in this part as though it were printed in full. When only a portion of a document is referenced, then this part incorporates only that referenced portion of the document and the remainder is not incorporated. Applicable editions are listed in paragraph (c) of this section in parentheses following the title of the referenced material. Earlier editions listed in previous editions of this section may be used for components manufactured, designed, or installed in accordance with those earlier editions at the time they were listed. The user must refer to the appropriate previous edition of 49 CFR for a listing of the earlier editions.

(b) All incorporated materials are available for inspection in the Pipeline and Hazardous Materials Safety Administration, PHP-30, 1200 New Jersey Avenue, SE, Washington, DC, 20590-0001, or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202-741-6030 or go to: http://www.archives.gov/federal_register/code_of_federal_regulations/IBR_locations.html.

Documents incorporated by reference are available from the publishers as follows:

A. American Gas Association (AGA), 400 North Capitol Street, NW, Washington, DC 20001.
B. American Petroleum Institute (API), 1220 L Street, NW, Washington, DC 20005.
C. American Society of Civil Engineers (ASCE), Parallel Centre, 1801 Alexander Bell Drive, Reston, VA 20191-4400.
D. ASME International (ASME), Three Park Avenue, New York, NY 10016-5990.
E. Gas Technology Institute (GTI, 1700 S. Mount Prospect Road, Des Plaines, IL 60018.
F. National Fire Protection Association (NFPA), 1 Batterymarch Park, P. O. Box 9101, Quincy, MA 02269-9101.

(c) Documents incorporated by reference.

Source and name of referenced material	49 CFR reference
A. American Gas Association (AGA):	
(1) "Purging Principles and Practices," (3rd edition, 2001).	§§ 193.2513; 193.2517; 193.2615.
B. American Petroleum Institute (API):	
(1) API Standard 620 "Design and Construction of Large, Welded, Low-Pressure Storage Tanks" (11th edition February 2008, addendum 1, March 2009).	§§ 193.2101(b); 193.2321(b)(2).
C. American Society of Civil Engineers (ASCE):	
(1) ASCE/SEI 7-05 "Minimum Design Loads for Buildings and Other Structures," (2005 edition, includes supplement No. 1 and Errata).	§ 193.2067(b)(1).
D. ASME International (ASME):	

(1) 2007 ASME Boiler and Pressure Vessel Code, Section VIII, Division 1, "Rules for Construction of Pressure Vessels," (2007 edition, July 1, 2007).	§ 193.2321(a).
(2) 2007 ASME Boiler and Pressure Vessel Code, Section VIII, Division 2, "Rules for Construction of Pressure Vessels – Alternative Rules,: (2007 edition, July 1, 2007).	§ 193.2321(a).
E. Gas Technology Institute (GTI) formerly the Gas Research Institute (GRI):	
(1) GTI-04/0032 LNGFIRE3: A Thermal Radiation Model for LNG Fires," (March 2004).	§ 193.2057(1).
(2) GTI-04/0049 (April 2004) "LNG Vapor Dispersion Prediction with the DEGADIS 2.1: Dense Gas Dispersion Model for LNG Vapor Dispersion".	§ 193.2059.
(3) GRI-96/0396.5 "Evaluation of Mitigation Methods for Accidental LNG Releases, Volume 5: Using FEM3A for LNG Accident Consequence Analyses," (April 1997).	§ 193.2059.
F. National Fire Protection Association (NFPA):	
(1) NFPA 59A (2001) "Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)."	§§ 193.2019; 193.2051; 193.2057; 193.2059; 193.2101(a); 193.2301; 193.2303; 193.2401; 193.2521; 193.2639; 193.2801.
(2) NFPA 59A, "Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)" (2006 edition, Approved August 18, 2005)	§§ 192.2101(b); 193.2321(b).

Section193.2057(a) is revised to read as follows: [6]

§ 193.2057 Thermal radiation protection.

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(a) The thermal radiation distances must be calculated using Gas Technology Institute's (GTI) report or computer model GTI-04/0032 LNGFIRE3: A Thermal Radiation Model for LNG Fires (incorporated by reference, *see* § 193.2013). The use of other alternate models which take into account the same physical factors and have been validated by experimental test data may be permitted subject to the Administrator's approval.

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Section 193.2067(b)(1) is revised to read as follows: [6]

§ 193.2067 Wind forces.

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(b)(1) For shop fabricated containers of LNG or other hazardous fluids with a capacity of not more than 70,000 gallons, applicable wind load data in ASCE/SEI 7-05 (incorporated by reference, *see* § 193.2013).

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<u>Section 193.2101 is revised to read as follows;</u> [6]

§ 193.2101 Scope.

(a) Each LNG facility designed after March 31, 2000 must comply with requirements of this Part and of NFPA 59A (2001) (incorporated by reference, *see* § 193.2013). If there is a conflict between this Part and NFPA 59A, this Part prevails. Unless otherwise specified, all references to NFPA 59A in this Part are to the 2001 edition.

(b) Stationary LNG storage tanks must comply with Section 7.2.2 of NFPA 59A (2006) (incorporated by reference, *see* § 193.2013) for seismic design of field fabricated tanks. All other LNG storage tanks must comply with API Standard 620 (incorporated by reference, *see* § 193.2013) for seismic design.

<u>Section 193.2321 is revised to read as follows:</u> [6]

§ 193.2321 Nondestructive tests.

(a) The butt welds in metal shells of storage tanks with internal design pressure above 15 psig must be nondestructively examined in accordance with the ASME Boiler and Pressure Vessel Code (Section VIII Division 1) (incorporated by reference, see § 193.2013), except that 100 percent of welds that are both longitudinal (or meridional) and circumferential (or latitudinal) of hydraulic load bearing shells with curved surfaces that are subject to cryogenic temperatures must be nondestructively examined in accordance with the ASME Boiler and Pressure Vessel Code (Section VIII Division 1) (incorporated by reference, see 193.2013).

(b) For storage tanks with internal design pressures at 15 psig or less, ultrasonic examinations of welds on metal containers must comply with the following:

  (1) Section 7.3.1.2 of NFPA 59A (2006) (incorporated by reference, see § 193.2013);

  (2) Appendices Q and C of API 620 Standard (incorporated by reference, see § 193.2013);

(c) Ultrasonic examination records must be retained for the life of the facility. If electronic records are kept, they must be retained in a manner so that they cannot be altered by any means; and

(d) The ultrasonic equipment used in the examination of welds must be calibrated at a frequency no longer than eight hours. Such calibrations must verify the examination of welds against a calibration standard. If the ultrasonic equipment is found to be out of calibration, all previous weld inspections that are suspect must be reexamined.

Section 199.7(a) is amended by: adding "U.S." before "Department of Transportation,''; adding "1200 New Jersey Avenue, SE'' before "Washington, DC''; and adding "-0001'' to the zip code "20590''. [2]

Section 199.229(c) is amended by adding "-0001'' to the zip code. [2]

Sources of changes to the Arkansas Gas Pipeline Code

1. Administrative Changes
2. **49 CFR Part 192 Amendment 192-109** [See U.S. DOT PHMSA Docket Number PHMSA-2007-0033, 74 FR 2889, January 16, 2009.]
3. **49 CFR Part 192 Amendment 192-115; 191-21; 193-23** [See U.S. DOT PHMSA Docket Number PHMSA-2008-0291, 75 FR 72878, November 26, 2010.]
4. **49 CFR Part 192 Amendment 192-116; 191-22** [See U.S. DOT PHMSA Docket Number PHMSA-RSPA-2004-19854, 76 FR 5494, February 1, 2011.]
5. **49 CFR Part 192 Amendment 192-112** [See U.S. DOT PHMSA Docket Number PHMSA-2007-27954, 74 FR 63310, December 3, 2009.]
6. **49 CFR Part 192 Amendment 192-114** [See U.S. DOT PHMSA Docket Number PHMSA-2008-0301, 75 FR 48593, August 11, 2010.]
7. **49 CFR Part 192 Amendment 192-107** [See U.S. DOT PHMSA Docket Number PHMSA-2005-23447, 73 FR 62148, October 17, 2008.]
8. **49 CFR Part 192 Amendment 192-110** [See U.S. DOT PHMSA Docket Number PHMSA-2008-0334, 74 FR 17099, April 14, 2009.]
9. **49 CFR Part 192 Amendment 192-111** [See U.S. DOT PHMSA Docket Number PHMSA-2009-0265, 74 FR 62503, November 30, 2009.]
10. **49 CFR Part 192 Amendment 192-108** [See U.S. DOT PHMSA Docket Number PHMSA-2005-21305, 73 FR 79002, December 24, 2008.]
11. **49 CFR Part 192 Amendment 192-113** [See U.S. DOT PHMSA Docket Number PHMSA—RSPA-2004-19854, 74 FR 63906, December 4, 2009.]
12. **49 CFR Part 192 Amendment 192-113** [See U.S. DOT PHMSA Docket Number PHMSA-RSPA-2004-19854, 75 FR 5244, February 2, 2010.]
13. **49 CFR Part 192 Amendment 192-112** [See U.S. DOT PHMSA Docket Number PHMSA-2007-27954, 75 FR 5536, February 3, 2010.]
14. **49 CFR Part 192 Amendment 192-117** [See U.S. DOT PHMSA Docket Number PHMSA- 2007-27954, 76 FR 5494, June 16, 2011.]
15. **49 CFR Part 192 Amendment 192-94** [See U.S. DOT RSPA Docket No. RSPA-99-6106; Amendment 192-94, 69 FR 32886, June 14, 2004.] Note: This amendment was originally incorporated into the code in Docket 06-123-R, at that time the decision was made not to incorporate this change as the Code would remain more stringent than the CFR.
16. **Change to Part 192.723 as recommended by Pipeline Safety personnel**