

RECEIVED
BLR
OCTOBER 20, 2025

ARKANSAS PUBLIC SERVICE COMMISSION



ARKANSAS GAS PIPELINE CODE FOR DESIGN, CONSTRUCTION, OPERATION INSPECTION AND MAINTENANCE OF NATURAL GAS SYSTEMS

August 16, 2025
REVISED Docket No. 25-025-R

Table of Contents

PREFACE.....	16
ADMINISTRATIVE HISTORY	17
DEFINITIONS.....	22
PART 190-PIPELINE SAFETY ENFORCEMENT PROCEDURES.....	27
SUBPART A - GENERAL	27
§ 190.1 Purpose.....	27
§ 190.3 Service	27
§ 190.5 Subpoenas; Witness Fees.....	27
§ 190.7 Extension of Time	27
§ 190.9 Petitions for Finding or Approval	27
§ 190.11 Waivers	28
SUBPART B - ENFORCEMENT	28
§ 190.15 Inspections, Production of Records, and Accident Investigations.....	28
§ 190.17 Notice of Probable Violation	28
§ 190.19 Show Cause Orders.....	29
§ 190.21 Response Options	29
§ 190.23 Case File	29
§ 190.25 Final Order.....	29
§ 190.27 Petitions for Reconsideration.....	29
§ 190.29 Civil Penalties	30
§ 190.31 Payment of Civil Penalties	30
SUBPART C - SPECIFIC RELIEF	30
§ 190.41 Hazardous Conditions.....	30
§ 190.43 Injunctive Action	30
PART 191 - TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE.....	31
ANNUAL REPORTS, INCIDENT REPORTS, AND SAFETY-RELATED CONDITION REPORTS	31
§ 191.1 Scope	31
§ 191.5 Immediate Notice of Certain Incidents	31
§ 191.7 Report Submission Requirements.....	32
§ 191.9 Distribution System: Incident Report.....	32
§ 191.11 Distribution System: Annual Report	33
§ 191.12 [Removed and Reserved].....	33
§ 191.13 Distribution Systems Reporting Transmission Pipelines: Transmission or Gathering Systems Reporting Distribution Pipelines.....	33
§ 191.15 Transmission Systems; Gathering Systems; and Liquefied Natural Gas Facilities:	

Incident Report.....	33
§ 191.17 Transmission Systems; Gathering Systems; and Liquefied Natural Gas Facilities: Annual Report.....	33
§ 191.21 OMB Control Number Assigned to Information Collection.....	34
§ 191.22 National Registry of Pipeline and LNG operators.....	34
§ 191.23 Reporting Safety-Related Conditions.....	35
§ 191.25 Filing Safety-Related Condition Reports.....	36
§ 191.27 Status of Leaks.....	37
§ 191.29 National Pipeline Mapping System	38
APPENDIX A TO PART 191- PROCEDURE FOR DETERMINING REPORTING THRESHOLD	39
PART 192 - TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM SAFETY STANDARDS	40
SUBPART A – GENERAL	40
§ 192.1 Scope	40
§ 192.3 Definitions.....	40
§ 192.5 Class Locations.....	44
§ 192.7 What documents are incorporated by reference partly or wholly in this part?	45
§ 192.8 How are onshore gathering lines and regulated onshore gathering lines determined?	49
§ 192.9 What requirements apply to gathering lines?.....	51
§ 192.11 Petroleum Gas Systems	52
§ 192.13 What general requirements apply to pipelines regulated under this part?	53
§ 192.14 Conversion to Service Subject to this Part	53
§ 192.15 Rules of Regulatory Construction	54
§ 192.16 Customer Notification.....	54
§ 192.17 Filing of Operation, Inspection, and Maintenance Plan.....	55
§ 192.18 How to Notify PHMSA.....	55
SUBPART B – MATERIALS.....	55
§ 192.51 Scope	55
§ 192.53 General.....	56
§ 192.55 Steel Pipe	56
§ 192.57 [Removed and Reserved]	56
§ 192.59 Plastic Pipe.....	56
§ 192.61 [Removed and Reserved]	57
§ 192.63 Marking of Materials	57
§ 192.65 Transportation of Pipe.....	58
§192.67 Records: Material properties	58
§192.69 Storage and Handling of Plastic Pipe and Associated Components	58

SUBPART C - PIPE DESIGN	59
§ 192.101 Scope	59
§ 192.103 General	59
§ 192.105 Design Formula for Steel Pipe	59
§ 192.107 Yield Strength (S) for Steel Pipe	59
§ 192.109 Nominal Wall Thickness (t) for Steel Pipe.....	60
§ 192.111 Design Factor (F) for Steel Pipe.....	60
§ 192.112 Additional Design Requirements for Steel Pipe Using Alternative Maximum Allowable Operating Pressure	60
§ 192.113 Longitudinal Joint Factor (E) for Steel Pipe	63
§ 192.115 Temperature Derating Factor (T) for Steel Pipe	64
§ 192.117 [Removed and Reserved].....	64
§ 192.119 [Removed and Reserved].....	64
§ 192.121 Design of Plastic Pipe	64
§ 192.123 [Removed and Reserved].....	68
§ 192.125 Design of Copper Pipe	68
§ 192.127 Records: Pipe Design.....	68
SUBPART D - DESIGN OF PIPELINE COMPONENTS	69
§ 192.141 Scope.....	69
§ 192.143 General Requirements	69
§ 192.144 Qualifying Metallic Components	69
§ 192.145 Valves.....	69
§ 192.147 Flanges and Flange Accessories.....	70
§ 192.149 Standard Fittings	70
§ 192.150 Passage of Internal Inspection Devices.....	71
§ 192.151 Tapping.....	71
§ 192.153 Components Fabricated by Welding.....	72
§ 192.155 Welded Branch Connections	74
§ 192.157 Extruded Outlets.....	74
§ 192.159 Flexibility	74
§ 192.161 Supports and Anchors.....	74
§ 192.163 Compressor Stations: Design and Construction.....	75
§ 192.165 Compressor Stations: Liquid Removal.....	76
§ 192.167 Compressor Station: Emergency Shut-Down.....	76
§ 192.169 Compressor Stations: Pressure Limiting Devices	76

§ 192.171 Compressor Stations: Additional Safety Equipment	76
§ 192.173 Compressor Stations: Ventilation.....	77
§ 192.175 Pipe-Type and Bottle-Type Holders.....	77
§ 192.177 Additional Provisions for Bottle-Type Holders	77
§ 192.179 Transmission Line Valves	78
§ 192.181 Distribution Line Valves	79
§ 192.183 Vaults: Structural Design Requirements	79
§ 192.185 Vaults: Accessibility.....	79
§ 192.187 Vaults: Sealing, Venting, and Ventilation	79
§ 192.189 Vaults: Drainage and Waterproofing	80
§ 192.191 [Removed and Reserved].....	80
§ 192.193 Valve Installation in Plastic Pipe.....	80
§ 192.195 Protection Against Accidental Overpressuring.....	80
§ 192.197 Control of Pressure of Gas Delivered from High-Pressure Distribution Systems.....	80
§ 192.199 Requirements for Design of Pressure Relief and Limiting Devices	81
§ 192.201 Required Capacity of Pressure Relieving and Limiting Stations	82
§ 192.203 Instrument, Control, and Sampling Pipe and Components.....	83
§ 192.204 Risers Installed After January 22, 2019	83
§ 192.205 Records: Pipeline Components.....	83
SUBPART E - WELDING OF STEEL IN PIPELINES.....	84
§ 192.221 Scope.....	84
§ 192.225 Welding - Procedures.....	84
§ 192.227 Qualification of Welders and Welding Operators.....	84
§ 192.229 Limitations on Welders and Welding Operators	85
§ 192.231 Protection from Weather	85
§ 192.233 Miter Joints	85
§ 192.235 Preparation for Welding	86
§ 192.241 Inspection and Test of Welds.....	86
§ 192.243 Nondestructive Testing	86
§ 192.245 Repair or Removal of Defects.....	87
SUBPART F - JOINING OF MATERIALS OTHER THAN BY WELDING	87
§ 192.271 Scope.....	87
§ 192.273 General	87
§ 192.275 Cast Iron Pipe	88
§ 192.277 Ductile Iron Pipe	88
§ 192.279 Copper Pipe	88
§ 192.281 Plastic Pipe.....	88

§ 192.283 Plastic Pipe: Qualifying Joining Procedures	89
§ 192.285 Plastic Pipe: Qualifying Persons To Make Joints	90
§ 192.287 Plastic Pipe: Inspection of Joints	91
SUBPART G - GENERAL CONSTRUCTION REQUIREMENTS FOR	
TRANSMISSION LINES AND MAINS.....	91
§ 192.301 Scope.....	91
§ 192.303 Compliance with Specifications or Standards	91
§ 192.305 Inspection: General.....	91
§ 192.307 Inspection of Materials	91
§ 192.309 Repair of Steel Pipe.....	91
§ 192.311 Repair of Plastic Pipe	92
§ 192.313 Bends and Elbows	92
§ 192.315 Wrinkle Bends in Steel Pipe	93
§ 192.317 Protection from Hazards.....	93
§ 192.319 Installation of Pipe in a Ditch.....	93
§ 192.321 Installation of Plastic Pipe.....	94
§ 192.323 Casing	95
§ 192.325 Underground Clearance.....	95
§ 192.327 Cover.....	95
§ 192.328 Additional Construction Requirements for Steel Pipe Using Alternative Maximum Allowable Operating Pressure	96
§192.329 Installation Of Plastic Pipelines By Trenchless Excavation	97
SUBPART H - CUSTOMER METERS, SERVICE REGULATORS, AND SERVICE LINES.....	
§ 192.351 Scope.....	97
§ 192.353 Customer Meters and Regulators: Location.....	97
§ 192.355 Customer Meters and Regulators: Protection from Damage	97
§ 192.357 Customer Meters and Regulators: Installation	98
§ 192.359 Customer Meter Installations: Operating Pressure	98
§ 192.361 Service Lines: Installation	98
§ 192.363 Service Lines: Valve Requirements.....	99
§ 192.365 Service Lines: Location of Valves	99
§ 192.367 Service Lines: General Requirements for Connections to Main Piping	99
§ 192.369 Service Lines: Connection to Cast Iron or Ductile Iron Mains	100
§ 192.371 Service Lines: Steel.....	100
§ 192.373 Service Lines: Cast Iron and Ductile Iron	100
§ 192.375 Service Lines: Plastic	100
§192.376 Installation Of Plastic Service Lines By Trenchless Excavation	100

§ 192.377	Service Lines: Copper	101
§ 192.379	New Service Lines Not in Use	101
§ 192.381	Service Lines: Excess Flow Valve Performance Standards.....	101
§ 192.383	Excess Flow Valve Installation.....	102
§ 192.385	Manual service line shut-off valve installation.....	102
SUBPART I - REQUIREMENTS FOR CORROSION CONTROL		104
§ 192.451	Scope.....	104
§ 192.452	How does this subpart apply to converted pipelines and regulated onshore gathering lines?.....	104
§ 192.453	General.....	104
§ 192.455	External Corrosion Control: Buried or Submerged Pipelines Installed After July 31, 1971	104
§ 192.457	External Corrosion Control: Buried or Submerged Pipelines Installed Before August 1, 1971	105
§ 192.459	External Corrosion Control: Examination of Buried Pipeline when Exposed	105
§ 192.461	External Corrosion Control: Protective Coating	106
§ 192.463	External Corrosion Control: Cathodic Protection	106
§ 192.465	External Corrosion Control: Monitoring.....	106
§ 192.467	External Corrosion Control: Electrical Isolation.....	107
§ 192.469	External Corrosion Control: Test Stations	108
§ 192.471	External Corrosion Control: Test Leads.....	108
§ 192.473	External Corrosion Control: Interference Currents	108
§ 192.475	Internal Corrosion Control: General	108
§ 192.476	Internal Corrosion Control: Design and Construction of Transmission Line.....	108
§ 192.477	Internal Corrosion Control: Monitoring.....	109
§ 192.479	Atmospheric Corrosion Control: General	109
§ 192.481	Atmospheric Corrosion Control: Monitoring.....	109
§ 192.483	Remedial Measures: General	110
§ 192.485	Remedial Measures: Transmission Lines	110
§ 192.487	Remedial Measures: Distribution Lines Other Than Cast Iron or Ductile Iron Lines ..	110
§ 192.489	Remedial Measures: Cast Iron and Ductile Iron Pipelines	111
§ 192.490	Direct Assessment	111
§ 192.491	Corrosion Control Records.....	111
§ 192.493	In-Line Inspection of Pipelines.....	112
SUBPART J - TEST REQUIREMENTS.....		112
§ 192.501	Scope.....	112
§ 192.503	General Requirements	112
§ 192.505	Strength Test Requirements for Steel Pipeline to Operate at a Hoop Stress of 30	

Percent or More of SMYS	113
§ 192.506 Transmission Lines: Spike Hydrostatic Pressure Test	113
§ 192.507 Test Requirements for Pipelines to Operate at a Hoop Stress Less Than 30 Percent of SMYS and at or Above 100 P.S.I. (689 kPa) Gage.....	114
§ 192.509 Test Requirements for Pipelines to Operate Below 100 P.S.I. (689 kPa) Gage.....	114
§ 192.511 Test Requirements for Service Lines	115
§ 192.513 Test Requirements for Plastic Pipelines.....	115
§ 192.515 Environmental Protection and Safety Requirements	115
§ 192.517 Records: Tests.....	116
SUBPART K - UPRATING.....	116
§ 192.551 Scope.....	116
§ 192.553 General Requirements	116
§ 192.555 Uprating to a Pressure That Will Produce a Hoop Stress of 30 Percent or More of SMYS in Steel Pipelines	117
§ 192.557 Uprating Steel Pipelines to a Pressure That Will Produce a Hoop Stress Less Than 30 Percent of SMYS: Plastic, Cast Iron, and Ductile Iron Pipelines.....	117
SUBPART L - OPERATIONS.....	119
§ 192.601 Scope.....	119
§ 192.603 General Provisions.....	119
§ 192.605 Procedural Manual for Operations, Maintenance, and Emergencies	119
§ 192.607 Verification of Pipeline Material Properties And Attributes: Onshore Steel Transmission Pipelines.....	121
§ 192.609 Change in Class Location: Required Study.....	123
§ 192.611 Change in Class Location: Confirmation or Revision of Maximum Allowable Operating Pressure.....	124
§ 192.613 Continuing Surveillance	125
§ 192.614 Damage Prevention Program	125
§ 192.615 Emergency Plans	126
§ 192.616 Public Awareness.....	127
§ 192.617 Investigation of Failures	128
§ 192.619 Maximum Allowable Operating Pressure: Steel or Plastic Pipelines	128
§ 192.620 Alternative Maximum Allowable Operating Pressure for Certain Steel Pipelines	130
§ 192.621 Maximum Allowable Operating Pressure: High-Pressure Distribution Systems.....	137
§ 192.622 Maximum Actual Operating Pressure: High-Pressure Distribution Systems.....	138
§ 192.623 Maximum and Minimum Allowable Operating Pressure: Low-Pressure Distribution Systems.....	138
§ 192.624 Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines	139
§ 192.625 Odorization of Gas	142

§ 192.627 Tapping Pipelines Under Pressure.....	143
§ 192.629 Purging of Pipelines.....	143
§ 192.631 Control Room Management	143
§ 192.632 Engineering Critical Assessment for Maximum Allowable Operating Pressure Reconfirmation: Onshore steel transmission pipelines	147
SUBPART M - MAINTENANCE.....	149
§ 192.701 Scope.....	149
§ 192.703 General.....	149
§ 192.705 Transmission Lines: Patrolling.....	149
§ 192.706 Transmission Lines: Leakage Surveys	150
§ 192.707 Line Markers for Mains and Transmission Lines	150
§ 192.709 Transmission Lines: Record-Keeping.....	151
§ 192.710 Transmission lines: Assessments outside of high consequence areas	151
§ 192.711 Transmission Lines: General Requirements for Repair Procedures.....	151
§ 192.712 Analysis of predicted failure pressure.....	151
§ 192.713 Transmission Lines: Permanent Field Repair of Imperfections and Damages	156
§ 192.715 Transmission Lines: Permanent Field Repair of Welds.....	156
§ 192.717 Transmission Lines: Permanent Field Repair of Leaks	157
§ 192.719 Transmission Lines: Testing of Repairs.....	157
§192.720 Distribution Systems: Leak Repair	157
§ 192.721 Distribution Systems: Patrolling	157
§ 192.723 Distribution Systems: Leakage Surveys and Procedures	158
§ 192.724 Hazardous Facilities.....	160
§ 192.725 Test Requirements for Reinstating Service Lines	160
§ 192.727 Abandonment or Deactivation of Facilities.....	160
§ 192.731 Compressor Stations: Inspection and Testing of Relief Devices.....	161
§ 192.735 Compressor Stations: Storage of Combustible Materials	161
§ 192.736 Compressor Stations: Gas Detection	161
§ 192.739 Pressure Limiting and Regulating Stations: Inspection and Testing	162
§ 192.740 Pressure regulating, limiting, and overpressure protection--Individual service lines directly connected to regulated gathering or transmission pipelines.....	163
§ 192.741 Pressure Limiting and Regulating Stations: Telemetry or Recording Gauges	163
§ 192.743 Pressure Limiting and Regulating Stations: Capacity of Relief Devices	164
§ 192.745 Valve Maintenance: Transmission Lines.....	164
§ 192.747 Valve Maintenance: Distribution Systems.....	164
§ 192.749 Vault Maintenance	164
§ 192.750 Launcher and receiver safety	165
§ 192.751 Prevention of Accidental Ignition.....	165

§ 192.753 Caulked Bell and Spigot Joints	165
§ 192.755 Protecting Cast Iron Pipelines.....	165
§192.756 Joining plastic pipe by heat fusion; equipment maintenance and calibration	166
SUBPART N - Qualification of Pipeline Personnel	166
§ 192.801 Scope.....	166
§ 192.803 Definitions	166
§ 192.805 Qualification Program	167
§ 192.807 Recordkeeping.....	167
§ 192.809 General	167
SUBPART O GAS TRANSMISSION PIPELINE INTEGRITY MANAGEMENT.....	168
§ 192.901 What do the regulations in this subpart cover?	168
§ 192.903 What definitions apply to this subpart?.....	168
§ 192.905 How does an operator identify a high consequence area?.....	170
§ 192.907 What must an operator do to implement this subpart?	170
§ 192.909 How can an operator change its integrity management program?	171
§ 192.911 What are the elements of an integrity management program?	171
§ 192.913 When may an operator deviate its program from certain requirements of this subpart?	172
§ 192.915 What knowledge and training must personnel have to carry out an integrity management program?.....	173
§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?	173
§ 192.919 What must be in the baseline assessment plan?	175
§ 192.921 How is the baseline assessment to be conducted?	176
§ 192.923 How is direct assessment used and for what threats?	177
§ 192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?	178
§ 192.927 What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?	179
§ 192.929 What are the requirements for using Direct Assessment for Stress Corrosion Cracking (SCCDA)?	181
§ 192.931 How may Confirmatory Direct Assessment (CDA) be used?	182
§ 192.933 What actions must be taken to address integrity issues?.....	182
§ 192.935 What additional preventive and mitigative measures must an operator take?.....	184
§ 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?	185
§ 192.939 What are the required reassessment intervals?	187
§ 192.941 What is a low stress reassessment?	189
§ 192.943 When can an operator deviate from these reassessment intervals?.....	190

§ 192.945	What methods must an operator use to measure program effectiveness?.....	190
§ 192.947	What records must an operator keep?.....	190
§ 192.949	[Removed and Reserved]	191
§ 192.951	Where does an operator file a report?	191
SUBPART P	GAS DISTRIBUTION PIPELINE INTEGRITY MANAGEMENT (IM).....	191
§ 192.1001	What definitions apply to this subpart?.....	191
§ 192.1003	What do the regulations in this subpart cover?.....	192
§ 192.1005	What must a gas distribution operator (other than a small LPG operator) do to implement this subpart?	192
§ 192.1007	What are the required elements of an integrity management plan?.....	192
§ 192.1009	[Removed and Reserved]	194
§ 192.1011	What records must an operator keep?	194
§ 192.1013	When may an operator deviate from required periodic inspections under this part?	194
§ 192.1015	What must a small LPG operator do to implement this subpart?	194
APPENDIX A TO PART 192	– RESERVED.....	196
APPENDIX B TO PART 192	- QUALIFICATION OF PIPE AND COMPONENTS.....	197
I.	Listed Pipe Specifications.....	197
II.	Steel Pipe of Unknown or Unlisted Specification.....	198
III.	Steel Pipe Manufactured Before November 12, 1970, to Earlier Editions of Listed Specifications.....	199
APPENDIX C TO PART 192	- QUALIFICATION OF WELDERS FOR LOW STRESS LEVEL PIPE	200
I.	Basic Test	200
II.	Additional Tests for Welders of Service Line Connections to Mains.....	200
III.	Periodic Tests for Welders of Small Service Lines.....	200
APPENDIX D TO PART 192	- CRITERIA FOR CATHODIC PROTECTION AND DETERMINATION OF MEASUREMENTS	201
I.	Criteria for Cathodic Protection	201
II.	Interpretation of Voltage Measurement	202
III.	Determination of Polarization Voltage Shift	202
IV.	Reference Half Cells.....	202
APPENDIX E TO PART 192	- GUIDANCE ON DETERMINING HIGH CONSEQUENCE AREAS AND ON CARRYING OUT REQUIREMENTS IN THE INTEGRITY MANAGEMENT RULE	203
I.	Guidance on Determining a High Consequence Area	203
II.	Guidance on Assessment Methods and Additional Preventive and Mitigative Measures for Transmission Pipelines	203
APPENDIX F TO PART 192	- Criteria for Conducting Integrity Assessments Using	

Guided Wave Ultrasonic Testing (GWUT)	207
PART 193 LIQUEFIED NATURAL GAS FACILITIES: FEDERAL SAFETY STANDARDS	211
SUBPART A – GENERAL	211
§ 193.2001 Scope of Part	211
§ 193.2003 [Reserved]	211
§ 193.2005 Applicability	211
§ 193.2007 Definitions	211
§ 193.2009 Rules of Regulatory Construction	213
§ 193.2011 Reporting	214
§ 193.2013 What documents are incorporated by reference partly or wholly in this part?	214
§ 193.2015 [Reserved]	215
§ 193.2017 Plans and Procedures	215
§ 193.2019 Mobile and Temporary LNG Facilities	215
SUBPART B – SITING REQUIREMENTS	216
§ 193.2051 Scope	216
§ 193.2055 [Reserved]	216
§ 193.2057 Thermal Radiation Protection	216
§ 193.2059 Flammable Vapor gas Dispersion Protection	216
§§ 193.2061-193.2065 [Reserved]	217
§ 193.2067 Wind Forces	217
§§ 193.2069-193.2073 [Reserved]	217
SUBPART C – DESIGN	217
§ 193.2101 Scope	217
Materials	217
§§ 193.2103-193.2117 [Reserved]	218
§ 193.2119 Records	218
Design of Components and Buildings	218
§§ 193.2121-193.2153 [Reserved]	218
Impoundment Design and Capacity	218
§ 193.2155 Structural Requirements	218
§§ 193.2157-193.2159 [Reserved]	219
§ 193.2161 Dikes, General	219
§§ 193.2163-193.2165 [Reserved]	219
§ 193.2167 Covered Systems	219
§§ 193.2169-193.2171 [Reserved]	219
§ 193.2173 Water Removal	219
§§ 193.2175-193.2179 [Reserved]	219

§ 193.2181 Impoundment Capacity: LNG Storage Tanks	219
§§ 193.2183-193.2185 [Reserved]	220
LNG Storage Tanks.....	220
§ 193.2187 Nonmetallic Membrane Liner	220
§§ 193.2189-193.2233 [Reserved]	220
SUBPART D – CONSTRUCTION.....	220
§ 193.2301 Scope	220
§ 193.2303 Construction Acceptance	220
§ 193.2304 Corrosion Control Overview	220
§§ 193.2305-193.2319 [Reserved]	220
§ 193.2321 Nondestructive Tests	220
§§ 193.2323-193.2329 [Reserved]	221
SUBPART E – EQUIPMENT.....	221
§ 193.2401 Scope	221
VAPORIZATION EQUIPMENT.....	221
§§ 193.2403-193.2439 [Reserved]	221
§ 193.2441 Control Center	221
§ 193.2443 [Reserved]	221
§ 193.2445 Sources of Power	221
SUBPART F – OPERATIONS.....	222
§ 193.2501 Scope	222
§ 193.2503 Operating Procedures	222
§ 193.2505 Cooldown	222
§ 193.2507 Monitoring Operations	222
§ 193.2509 Emergency Procedures	223
§ 193.2511 Personnel Safety	223
§ 193.2513 Transfer Procedures	223
§ 193.2515 Investigations of Failures	224
§ 193.2517 Purging	225
§ 193.2519 Communication Systems	225
§ 193.2521 Operating Records	225
SUBPART G – MAINTENANCE.....	225
§ 193.2601 Scope	225
§ 193.2603 General	225
§ 193.2605 Maintenance Procedures	226
§ 193.2607 Foreign Material	226
§ 193.2609 Support Systems	226

§ 193.2611 Fire Protection	226
§ 193.2613 Auxiliary Power Sources	226
§ 193.2615 Isolating and Purging	227
§ 193.2617 Repairs	227
§ 193.2619 Control Systems	227
§ 193.2621 Testing Transfer Hoses	227
§ 193.2623 Inspecting LNG Storage Tanks	228
§ 193.2625 Corrosion Protection	228
§ 193.2627 Atmospheric Corrosion Control	228
§ 193.2629 External Corrosion Control; Buried or Submerged Components	228
§ 193.2631 Internal Corrosion Control	229
§ 193.2633 Interference Currents	229
§ 193.2635 Monitoring Corrosion Control	229
§ 193.2637 Remedial Measures	229
§ 193.2639 Maintenance Records	229
§ 193.2703 Design and Fabrication	230

PART 199 - DRUG AND ALCOHOL TESTING	234
SUBPART A - GENERAL	234
§ 199.1 Scope	234
§ 199.2 Applicability	234
§ 199.3 Definitions	235
§ 199.5 DOT Procedures	235
§ 199.7 Stand-down Waivers	236
§ 199.9 Preemption of State and Local Laws	236
SUBPART B – DRUG TESTING	236
§ 199.100 Purpose	236
§ 199.101 Anti-Drug Plan	236
§ 199.103 Use of Persons Who Fail or Refuse a Drug Test	237
§ 199.105 Drug Tests Required	237
§ 199.107 Drug Testing Laboratory	239
§ 199.109 Review of Drug Testing Results	239
§ 199.111 [Removed and Reserved]	240
§ 199.113 Employee Assistance Program	240
§ 199.115 Contractor Employees	240
§ 199.117 Record Keeping	240
§ 199.119 Reporting of Anti-Drug Testing Results	241

SUBPART C _ ALCOHOL MISUSE PREVENTION PROGRAM..... 242

§ 199.200 Purpose..... 242

§ 199.201 [Reserved]..... 242

§ 199.202 Alcohol Misuse Plan..... 242

§§ 199.203-199.205 [Reserved]..... 242

§ 199.209 Other Requirements Imposed by Operators..... 242

§ 199.211 Requirements for Notice..... 242

§ 199.213 [Reserved]..... 242

§ 199.215 Alcohol Concentration..... 243

§ 199.217 On-duty Use..... 243

§ 199.219 Pre-duty Use..... 243

§ 199.221 Use Following an Accident..... 243

§ 199.223 Refusal to Submit to a Required Alcohol Test..... 243

§ 199.225 Alcohol Tests Required..... 243

§ 199.227 Retention of Records..... 245

§ 199.229 Reporting of Alcohol Testing Results..... 246

§ 199.231 Access to Facilities and Records..... 247

§ 199.233 Removal from Covered Function..... 247

§ 199.235 Required Evaluation and Testing..... 248

§ 199.237 Other Alcohol-related Conduct..... 248

§ 199.239 Operator Obligation to Promulgate a Policy on the Misuse of Alcohol..... 248

§ 199.241 Training for Supervisors..... 249

§ 199.243 Referral, Evaluation, and Treatment..... 249

§ 199.245 Contractor Employees..... 250

PREFACE

ARKANSAS GAS PIPELINE CODE

On August 12, 1968, the United States Congress passed Public Law 90-481, better known as the Natural Gas Pipeline Safety Act of 1968. This Act authorizes the Secretary of Transportation to administer this law, and to develop standards and regulate the enforcement of such standards for the design, installation, inspection, testing, construction, extension, operation, replacement and maintenance of pipeline facilities. Enacted on July 5, 1994, Public Law 103-272 revised, codified, and enacted the provisions of the Act without substantive change as Chapter 601 of Title 49, United States Code. Title 49 U.S.C. 60105 authorizes a state to regulate these minimum standards under a certification to the Secretary of Transportation that provides certain provisions are met by the state.

On March 15, 1971, the Arkansas General Assembly enacted Act 285 of 1971, the Arkansas Natural Gas Pipeline Safety Act of 1971, codified as Ark. Code Ann. § 23-15-201 *et seq.* Act 285 authorized the Arkansas Public Service Commission to administer a state program pertaining to the design, installation, inspection, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities used to transport natural gas. The Pipeline Safety Office was established and tasked with the responsibility of developing and implementing this program. Act 285 is far-reaching and affects directly or indirectly persons who distribute or use natural gas.

As long as natural gas flows through a closed controlled system, it remains an efficient, inexpensive and safe servant. However, when it escapes from its pipes, gas can turn on man violently and quickly. In passing the Arkansas Natural Gas Pipeline Safety Act of 1971, the Arkansas General Assembly intended to provide laws and standards which assured that these systems would continue to be operated in a safe manner and thereby reduce the possibility of gas escaping from its closed system. The objective of the pipeline safety program within Arkansas is to keep the gas confined to a closed, controlled system. This is best accomplished by requiring gas companies, operators of gas systems, and all persons who install natural gas pipelines to install and maintain them using only authorized materials and procedures and to comply with standards designed to ensure continuing quality of operation and maintenance.

The procedures and standards adopted by the Arkansas Public Service Commission, as authorized by Act 285, are known as the Arkansas Gas Pipeline Code. Compliance with the Code is mandatory under state law and non-compliance by any person engaging in the transportation of gas or who owns or operates pipeline facilities is punishable by a civil penalty not to exceed \$200,000 per violation for each day the violation continues, except that the maximum civil penalty may not exceed \$2,000,000 for any related series of violations. The law also provides authority for the Commission to file suit to restrain violations of the Code, including the restraint of transportation of gas or the operation of a pipeline facility.

The Arkansas Gas Pipeline Code is comprised of Parts 190, Enforcement Procedures; 191, Annual and Incident Reports; 192, Minimum Safety Standards; ~~193, Liquefied Natural Gas Facilities;~~ and 199, Drug and Alcohol Testing. The paragraphs in Parts 191, 192, ~~193,~~ and 199 correspond to the paragraph numbers of Parts 191, 192, ~~193,~~ and 199 of Title 49, Code of Federal Regulations, Pipeline Safety Regulations.

ADMINISTRATIVE HISTORY
of the
ARKANSAS GAS PIPELINE CODE

Docket	Effective Date	Order No.	Subject Matter of Docket/Order
U-2424 (72-024-U)	01/03/1973	---	Adoption of Arkansas Gas Pipeline Code
U-2683 (75-082-U)	01/30/1976	---	General Revisions to Code.
U-2794 76-109-U)	02/24/1977	---	General Revisions to Code.
U-2908 (77-008-U)	02/03/1978	---	General Revisions to Code.
U-2999 (78-055-U)	02/15/1979	---	General revision to Code with emphasis on corrosion requirements.
U-3083 (80-007-U)	03/18/1980	2	Adds requirements for qualifying persons and procedures for the joining of plastic pipe.
81-040-U	03/11/1081	3	Amends requirements concerning plastic pipe joining and external corrosion control monitoring.
82-059-R	04/16/1982	6	Adds Part 190 – Pipeline Safety Procedures, and updates industry standards publications.
83-015-R	03/07/1983	2	Adds requirements for a Damage Prevention Program and provides flexibility in scheduling inspections and tests.
84-034-R	07/06/1984	4	General Code revisions.
85-086-R	08/21/1985	3	Revised Part 191 - Transportation of Natural and Other Gas by Pipeline: Annual Reports and Incident Reports. Also revised the Code format. Complete republication by Order No. 4.
86-169-R	12/15/1986	3	Revised definition of operator. Amends provision regarding plastic pipe, welder qualification, preheating, and stress relieving.
88-005-R	07/14/1988	4	Revised Part 190 to provide for waivers, response to accident recommendations, and numbered paragraphs. Part 192 amended for locations, MAOP, testing repairs, odorization damage prevention, and R/V calculation.
89-034-R	08/02/1989	3	Part 191 amended to include Safety-Related Condition Reports. Part 192 amended for deletion references, adding requirements for safety conditions to be included in O&M plans, and requirements for tie-in joints.
	08/22/1989	5	Added Part 199 – Drug Testing. Establishes employee drug testing program required of operators subject to Part 192.
90-015-R	03/23/1990	3	General revisions with emphasis on updating of Standards & Specifications; class location vs. MAOP; cast/ductile iron, and copper pipe; Part 199 - changes

			caused by deletion of "Rehabilitation Committee" and its definition; and changes in Drug tests required.
91-056-R	06/06/1991	3	Care when using tracer wire with plastic pipe, and lubrication requirements for valves.
92-036-R	05/12/1992	3	Parts 192 and 199 changed to reflect requirement of operators to amend plans and procedures as necessary for safety. Preface and Part 190 changed to reflect increase in civil penalties.
93-020-R	04/26/1993	3	Parts 191 and 192 changed to include gathering lines containing 100 ppm or more of hydrogen sulfide. Part 192 further changed by correcting certain discrepancies not previously discovered. Code format revised and complete republication of the Arkansas Gas Pipeline Code.
94-025-R	09-12-1994	4	Update of referenced Standards, addition of requirement for gas detection in compressor station buildings, and clarification of leakage survey requirements. Part 199 changes keeping and a new requirement for a report on the anti-drug program.
95-116-R	04/27/1995	3	Definitions section and Parts 190 and 192 changed reflect the requirement that certain new and replacement pipelines be designed and constructed to accommodate instrumented internal inspection devices. Part 190 changed to clarify the language in the issuance and handling of show cause orders. Part 192 changed to require meters which have been installed indoors to be in a ventilated place and not less than 3 feet from any source of ignition or source of heat which might damage the meter, to require detailed procedures in O&M manuals, that operators review and update their O&M manuals each year, and that operators prepare and follow procedures to safeguard personnel from unsafe accumulations of vapors or gas in excavated trenches. Part 199 reformatted to add Subpart B, Alcohol Misuse Prevention Program. Preface changed to include new title of Part 199. Complete republication of the Arkansas Gas Pipeline Code.
96-181-R	08/20/1996	3	Preface and Part 190 changed to reflect civil penalties. Part 192 changed to include notification requirement for customer-owned service lines, to extend existing excavation damage prevention requirements for gas pipelines in urban areas to gas pipelines in rural areas, and to require, with limited exceptions, line markers for transmission lines in urban areas. Part 199 changed to allow for the possibility of a reduced random drug testing rate, and to require reporting of information concerning missed tests. Complete republication of the Arkansas Gas Pipeline Code.

97-034-R	04/03/1997	3	Preface changed to explain the codification of Natural Gas Pipeline Safety Act. Definition of "petroleum gas" added and definition of "transmission line" revised in the Definitions section. Numerous minor changes to Parts 191 and 192. Addition of performance standards for excess flow valves to Part 192. Appendices A and B to Part 192 updated. Minor revisions to Part 199. Complete republication of the Arkansas Gas Pipeline Code.
99-130-R	08/02/1999	3	All Parts changed to include metric equivalents for English measures. Part 192 changed to require Excess Flow Valves ("EFO") close at 50% or of the manufacturer's rated closure flow rate operating at 10 pounds per square inch ("p.s.i.g."); removed the requirement to installation of EFO's beneath hard surfaces; operators to notify customers of the option to install EFO's before the installation or replacement of service lines; require that all operators must participate in a qualified one-call system; added transmission or distribution of gas containing H2S to reflect the exact language in Arkansas Code Annotated 23-15-203 (3); removed atmospheric corrosion requirements for offshore facilities. Appendix A revised to incorporate certain versions of The American Society for Testing and Materials Standards by reference. Part 199 revised to clarify terms; added requirements for a Substance Abuse Professional ("SAP"). Complete republication of the Arkansas Gas Pipeline Code.
00-312-R	12/11/2000	4	Part 190.15 revised to include falsification paperwork as probable violation. Part 192.17 revised to allow the use of a certified letter for notification of probable violation. New Subpart N - Operator Qualification added. Minor changes to Subpart I and M. Complete republication of the Arkansas Gas Pipeline Code.
04-088-R	08/26/2004	3	Adopted Federal Office of Pipeline Safety Amendments 192-86A, 192-89, 192-89A, 192-93, 192-95, 199-19 and 199-21.
06-123-R	12/07/2006	3	Adopted Federal Pipeline and Hazardous Material Safety Administration Amendments 192-96, 192-97, 192-98, 192-99, 192-100, 192-102, 192-103, 199-20, 49 CFR Part 193 in entirety, Amendment 193-19, Nomenclature amendment regarding the change of the Research Special Programs Administration into the Pipeline and Hazardous Materials Safety Administration Act, the 82 nd General Assembly of the Arkansas Legislature, and Act 153 of the 83 rd General

			Assembly of the Arkansas Legislature. Complete republication of the Arkansas Gas Pipeline Code.
08-167-R	05/04/2009	3	Adopted Federal Pipeline and Hazardous Safety Administration amendment 192-103A, update of regulatory references to technical standards, amendment regarding design and construction standards to reduce internal corrosion in gas transmission pipelines, 192-104 Integrity Management Program modifications and clarifications, amendment regarding applicability of public awareness regulation to certain gas distribution operators, and amendment regarding administrative procedures, address updates, and technical amendments. Complete republication of the Arkansas Gas Pipeline Code.
11-166-R	06/08/2012	5	Adopted Federal Pipeline and Hazardous Material Safety Administration (“PHMSA”) 108, 109, 110, 111, 112, 114, and 115 to Part Adopted PHMSA amendments 22 and 23 to Part Adopted PHMSA amendment 21 to Part Complete republication of the Arkansas Gas Code.
13-027-R	10/16/2013	3	Editorial changes, adopted Private Line definition, added 192.27 Status of Leaks requirement, and added 192.724 Hazardous Facilities requirement.
14-029-R	09/25/2014	5	Adopted Federal Pipeline and Hazardous Material Safety Administration amendment to incorporate higher civil penalties and minor redesignation changes. Also incorporated changes from Act 1343 of 2013 from the Arkansas General Assembly. Complete republication of the Arkansas Gas Pipeline Code.
16-093-R	05/19/2017	4	Adopted 2015 Federal Pipeline and Hazardous Material Safety Administration amendments 191-23, 192-119, 192-120, 193-25, and 199-26 (80 FR 168, 12762, and 46847-01); and made technical corrections. Complete republication of the Arkansas Gas Pipeline Code.
19-069-R	03/31/2020	4	Adoption of 2016 and 2017 Federal Pipeline and Hazardous Material Safety Administration amendments 190-19 and 192-121 (81 FR 72739 and 82 FR 7972) and made technical corrections. Complete republication of the Arkansas Gas Pipeline Code.
22-020-R	8/18/2022	3	Adoption of 2019, 2020, 2021, and 2022 Federal Pipeline and Hazardous Material Safety Administration amendments 192-124, 191-26, 192-125, 192-127, 191-29, 192-128, (83 FR 58694, 84 FR 16770, 84 FR 52180, 85 FR 40132, 86 FR 2210, and 86 FR 12835.

DEFINITIONS

DEFINITIONS OF WORDS/PHRASES USED IN THE ARKANSAS GAS PIPELINE CODE

Except as otherwise provided in this Code:

Abandoned means permanently removed from service.

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

Administrator means the Administrator of the Pipeline and Hazardous Materials Safety Administration or any person to whom authority in the matter concerned has been delegated by the U.S. Secretary of Transportation.

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

Business District means a location where gas mains are utilized to serve customers that are predominately commercial in nature, and where the street and/or sidewalk paving generally extends from the centerline of a thoroughfare to the established building line on either side.

Change to a segment of pipeline means a physical change in the pipeline or significant changes in operating pressure.

Commission means, unless the context otherwise requires, the Arkansas Public Service Commission or any person or entity to whom the Commission has delegated authority in the matter concerned.

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

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

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

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

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

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

Emergency Order means a written order issued in response to an imminent hazard imposing restrictions, prohibitions, or safety measures on owners and operators of gas or hazardous liquid pipeline facilities, without prior notice or an opportunity for hearing.

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

Gathering Line means a pipeline that transports gas from a current production facility to a transmission line or main.

High Pressure Distribution System means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer.

Imminent hazard means the existence of a condition relating to a gas or hazardous liquid pipeline facility that presents a substantial likelihood that death, serious illness, severe personal injury, or a substantial endangerment to health, property, or the environment may occur before the reasonable foreseeable completion date of a formal proceeding begun to lessen the risk of such death, illness, injury, or endangerment.

Incident means any of the following events:

- (1) An event that involves a release of gas from a pipeline, gas from an underground natural gas storage facility, ~~liquefied natural gas, or gas from an LNG facility~~, and that results in one or more of the following consequences:
 - (i) A death, or personal injury necessitating in-patient hospitalization;
 - (ii) Estimated property damage of \$122,000 or more, including loss to the operator and others, or both, but excluding the cost of gas lost; For adjustments for inflation observed in calendar year 2021 onwards, changes to the reporting threshold will be posted on PHMSA's website. These changes will be determined in accordance with the procedures in Appendix A to part 191; or
 - (iii) Unintentional estimated gas loss of three million cubic feet or more.
- ~~(2) An event that results in an emergency shutdown of an LNG facility or an underground natural gas storage facility. Activation of an emergency shutdown system for reasons other than an actual emergency does not constitute an incident.~~
- ~~(3)~~⁽²⁾ An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraph (1) or (2) of this definition.

Key Valves means shut off valves in a distribution system or transmission line which may be necessary to isolate segments of a system or line for emergency purposes.

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

Listed Specification means a specification listed in Section I of Appendix B to Part 192.

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

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

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

Maximum Actual Operating Pressure means the maximum pressure that occurs during

normal operations over a period of one year.

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

Mobile Home Park means two or more mobile homes located on a contiguous tract of land.

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

Manual service line shut-off valve means a curb valve or other manually operated valve located near the service line that is safely accessible to operator personnel or other personnel authorized by the operator to manually shut off gas flow to the service line, if needed.

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

Operator means a person who:

- (1) Engages in the transportation of gas; or
- (2) Operates a distribution system within a mobile home park, public housing authority, or multiple building complex if:
 - (A) The system:
 - (i) Is not owned, nor the responsibility of a public or municipal utility; and
 - (ii) Is used to transport gas from a master meter or a public/municipal utility main to consumers who may or may not be metered; and
 - (B) The gas distributed is not consumed solely by the owner/operator.

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

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 p.s.i.g. (1434 kPa) gage at 100°F (38°C).

Petroleum Refinery means an industrial or manufacturing facility or plant primarily engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants or other products through the processing of petroleum crude oil that is subject to:

- (A) The federal Environmental Protection Agency Standards of Performance for New Stationary Sources set forth in Subpart GGG of 40 CFR Part 60 or successor regulations;
- (B) The federal *Environmental* Protection Agency Chemical Accident Prevention Provisions set forth in Subparts, A, B, D, E, F, G, and H of 40 CFR Part 68 or successor *regulations*; and
- (C) The federal Occupational Safety and Health Administration Regulations governing process safety management of highly hazardous chemicals set forth in 29 CFR §1910.119 or successor regulations.

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

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

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

Pipeline Facilities includes without limitation, new and existing pipe, pipe rights-of-way, and any equipment, facility or building used in the transportation of gas or the treatment of gas during the course of transportation of gas.

Pipeline Safety Office or PSO means the Pipeline Safety Office within the Arkansas Public Service Commission that administers the Arkansas Natural Gas Pipeline Safety Act of 1971, Arkansas Code § 23-15-201 *et seq.*, the Arkansas Gas Pipeline Code, and related laws, rules, and regulations.

Production Facilities includes without limitation, piping or equipment used in the production, extraction, recovery, lifting, stabilization, separation or treatment of natural gas or associated storage or measurement from the wellhead to a meter where the gas is transferred to a custodian other than the well operator for gathering or transport, commonly known as a “custodial transfer meter.”

Production Process means the extraction of gas from the geological source of supply to the surface of the earth, thence through the lines and equipment used to treat, compress and measure the gas between the wellhead and the meter where it is either sold or delivered to a custodian other than the well operator for gathering and transport to a place of sale, sometimes called a “custodial transfer meter.”

Service Line means a distribution line that transports gas from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer’s piping, whichever is further downstream, or at the connection to customer piping if there is no meter.

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

SMYS means specified minimum yield strength, and is:

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

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.

Test Failure means a break or rupture that occurs during strength proof testing of transmission or gathering lines that are of such magnitude as to require repair before continuation of the test.

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

- (1) Transports gas from a gathering line or storage facility to a gas distribution center, storage facility, or large volume customer that is not down-stream from a gas distribution center;
- (2) Operates at a hoop stress of 20 percent or more SMYS; or
- (3) Transports gas within a storage field.

NOTE: A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

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

PART 190-PIPELINE SAFETY ENFORCEMENT PROCEDURES

SUBPART A - GENERAL

§ 190.1 Purpose

This part prescribes procedures utilized by the Arkansas Public Service Commission (Commission) in carrying out its responsibilities regarding pipeline safety under the Arkansas Natural Gas Pipeline Safety Act of 1971 (Act 285 of 1971, as amended; Ark. Code Ann. § 23-15-201 et seq.). Any conflict between the Commission's Rules and Regulations and the Arkansas Statutes shall be resolved in favor of the statutes.

§ 190.3 Service

Each show cause order issued under this part shall be served in accordance with the current provisions of the Commission's Rules of Practice and Procedure and Ark. Code Ann. §23-2-405.

§ 190.5 Subpoenas; Witness Fees

The issuance of subpoenas and payment of witness fees shall be in accordance with the current provisions of the Commission's Rules of Practice and Procedure and Ark. Code Ann. §23-2-402 and § 23-2-414.

§ 190.7 Extension of Time

In those instances when the actions necessary to correct documented deficiencies will exceed the time limit given in the notice of probable violation, an operator may request an extension of time in order to effect compliance. Each request must detail the reason(s) why compliance cannot be accomplished by the original suspense date, and the date the operator believes the necessary compliance actions can be completed. If the Commission finds the request to be reasonable a new suspense date may be established.

§ 190.9 Petitions for Finding or Approval

- (a) In circumstances where a rule contained in Part 192 ~~or Part 193~~ authorizes the Administrator of the Pipeline and Hazardous Materials Safety Administration of the United States Department of Transportation to make a finding or approval, an operator may petition the Administrator for such a finding or approval.
- ~~(b)~~ (1) Each petition must refer to the rule authorizing the action sought and contain information or arguments that justify the action. Unless otherwise specified, no public proceeding is held on a petition before it is granted or denied. After a petition is received, the Administrator or participating state agency notifies the petitioner of the disposition of the petition or, if the request requires more extensive consideration or additional information or comments are requested and delay is expected, of the date by which action will be taken.
- (2) For operators seeking a finding or approval involving intrastate pipeline transportation, petitions must be sent to: Pipeline Safety Office, Arkansas Public Service Commission, P.O. Box 400, Little Rock, Arkansas 72203-0400.
- (3) For operators seeking a finding or approval involving interstate pipeline transportation, petitions must be sent to the Administrator, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue, SE, Washington, DC 20590.

~~(b)(c)~~ All petitions must be received at least 90 days prior to the date by which the operator

requests the finding or approval to be made.

- (d) The Administrator will make all findings or approvals of petitions initiated under this section. The Pipeline Safety Office (PSO), upon receiving petitions initiated under this paragraph, shall provide the Administrator a written recommendation by certified mail, return receipt requested as to the disposition of any petition received by the PSO. If the Administrator does not reverse or modify a recommendation made by the PSO within 10 business days of its receipt, the recommended disposition shall constitute the Administrator's decision on the petition.

§ 190.11 Waivers

If unusual difficulty results from implementing a safety standard in Part 192 ~~or Part 193~~, application may be made to the Commission for exemption from a particular standard. The application for exemption shall be accompanied by a thorough justification for requested actions.

SUBPART B - ENFORCEMENT

§ 190.15 Inspections, Production of Records, and Accident Investigations

- (a) The Commission may conduct inspections and investigate accidents in accordance with Ark. Code Ann. §23-15-207. Operators are required to provide records requested by the Commission pursuant to Ark. Code Ann. §23-15-206 for any inspection or accident investigation.
- (b) If an inspection or accident investigation indicates that a probable violation exists, or if an operator falsifies records, or fails to provide any record(s) requested by the Commission, a notice of probable violation will be sent to the operator. For the purposes of this rule, a probable violation for failing to provide records shall arise only from failure to provide records required by § 190.15 (a) in the form in which they are maintained in the ordinary course of business. The operator shall be allowed the time prescribed by the Commission's Rules of Practice and Procedure to respond after service of any such request for records. For purposes of this rule, falsifying records shall mean "the original entry or subsequent modification of any official record with the intent to mislead or deceive a third party later examining the document."
- (c) If an accident investigation results in the PSO making recommendations in a formal accident investigation report, the operator will make written response to those recommendations within the time frame specified in the report.

§ 190.17 Notice of Probable Violation

- (a) The Commission begins enforcement proceedings by serving a notice of probable violation of the Arkansas Gas Pipeline Code or any order issued thereunder. This notification shall advise the operator that a written response is required and that failure to respond may result in enforcement action in accordance with § 190.19.
- (b) A notice of probable violation issued under this section shall include:
- (1) Statement of the provisions of the laws, regulations or orders which the respondent is alleged to have violated and a statement of the evidence upon which the allegations are based;
 - (2) Notice of response options available to the respondent.
- (c) The notice of probable violation shall normally be in the form of an inspection report mailed

to the person charged. However, the notice of probable violation may be served in the form of a certified letter or show cause order.

- (d) A notice of probable violation for failure to produce or falsification of records may be served in the form of a certified letter or show cause order. Falsification of records may also be referred to the Inspector General of the U.S. Department of Transportation for investigation and prosecution under applicable provisions of federal criminal law.

§ 190.19 Show Cause Orders

The Commission may issue a show cause order notifying the owner or operator of a probable violation and advising the person to correct it or be subject to enforcement action. The severity of the probable violation shall be the determining factor in the type of notice issued by the Commission. A show cause order shall be served as provided in § 190.3.

§ 190.21 Response Options

An operator has 20 calendar days from the date of receipt of a show cause order to respond. The operator may:

- (a) Submit written response to the allegations. The written response may contain one of the following:
 - (1) Evidence to rebut the allegations of the show cause order; or
 - (2) Actions taken to achieve compliance; or
 - (3) A request for an extension of time to correct the alleged probable violation(s).
- (b) Request a hearing.
 - (1) A request for a hearing shall be in writing and shall conform to the Commission's Rules of Practice and Procedure.

Failure of the operator to respond in a timely manner to a show cause order under either subsection (a) or (b) of this section shall constitute a waiver of the operator's right to contest the allegations. The Commission may then act on the basis of the case file compiled by the Staff.

§ 190.23 Case File

The Case File compiled by the Staff after the issuance of a show cause order shall contain the following information:

- (a) The inspection reports and any other evidence of alleged violations;
- (b) A copy of the show cause order;
- (c) Any material submitted by the operator pursuant to § 190.21(a); and
- (d) The evaluation of the Staff and their recommendations for final action.

§ 190.25 Final Order

The Commission shall issue a final order at the conclusion of any proceedings initiated by a show cause order. The final order shall include:

- (a) Findings of fact addressing all material issues and conclusions of law;
- (b) A statement of the amount of the civil penalty, if any, and the procedures for the payment of the penalty; and
- (c) A statement of the necessary actions to be taken by the operator and a schedule for completion of those actions, if any are found to be necessary.

§ 190.27 Petitions for Reconsideration

Subsequent to a final order, the operator may request a rehearing pursuant to Ark. Code Ann. § 23-2-422, and the Commission's Rules of Practice and Procedure.

§ 190.29 Civil Penalties

The Commission may assess civil penalties prescribed by Ark. Code Ann. § 23-15-211 for violations of the Arkansas Gas Pipeline Code which as of July 1, 2016, shall not exceed two hundred thousand dollars (\$200,000) for each violation for each day that the violation persists, except that the maximum civil penalty shall not exceed two million dollars (\$2,000,000) for any related series of violations. Before assessing a civil penalty, the Commission shall follow the procedures established by §§ 190.19 and 190.25.

§ 190.31 Payment of Civil Penalties

Any civil penalty not promptly paid to the Commission shall be recovered with interest thereon from the date of the order in a civil action brought by the Commission under Ark. Code Ann. §§ 23-15-211 - 23-15-212.

SUBPART C - SPECIFIC RELIEF

§ 190.41 Hazardous Conditions

- (a) Whenever the Commission finds a particular facility to be hazardous to life or property, it shall be empowered to require the person operating such facility to take such corrective measures necessary to remove such hazards.
- (b) Where the operator contests the corrective measures imposed by the Commission, the operator may request a hearing which shall be made in writing and shall conform to the Commission's Rules of Practice and Procedure. A request for a hearing under this paragraph shall not act to stay the corrective measures initially required by the Commission.

§ 190.43 Injunctive Action

The Commission may restrain violations of the Arkansas Natural Gas Pipeline Safety Act of 1971, as amended, by seeking injunctive relief pursuant to Arkansas Code Ann. §23-15-212.

PART 191 - TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE:

ANNUAL REPORTS, INCIDENT REPORTS, AND SAFETY-RELATED CONDITION REPORTS

§ 191.1 Scope

- (a) This part prescribes requirements for the reporting of incidents, safety-related conditions, and annual pipeline summary data, ~~and applies to all persons engaged in the transportation of gas. Leaks/ignition which were intentionally caused by the operator are not reportable.~~, National Registry of Operators information, and other miscellaneous conditions by operators of underground natural gas storage facilities and natural gas pipeline facilities located in the United States or Puerto Rico.
- (b) Sections 191.22(b) and (c) and 191.23 do not apply to the onshore gathering of gas –
- (1) Through a pipeline that operates at less than 0 psig (0kPa); or
 - (2) Through a pipeline that is not a regulated onshore gathering pipeline.

~~(2) This part does not apply to leaks and test failures that occur in the gathering of gas through a pipeline that operates at less than 0 p.s.i.g. (0 kPa), and through a pipeline that is not a regulated onshore gathering line (as determined in § 192.8 of this subchapter); however it shall apply to the gathering, transmission or distribution of gas containing 100 or more parts-per-million of hydrogen sulfide from the custodial transfer meter through any pipeline, rural or non-rural, to and through any pipeline facility that removes hydrogen sulfide except that portion of such a pipeline or pipeline facility that is located within the fenced boundary of a petroleum refinery. For those lines that are jurisdictional solely on the basis of their hydrogen sulfide content, the reports required by this part shall be submitted to the PSO and not to the U.S. Department of Transportation.~~

§ 191.5 Immediate Notice of Certain Incidents

- (a) At the earliest practicable moment following discovery, but no later than one hour after confirmed discovery, each operator must give notice in accordance with paragraph (b) and (d) of this section of each incident as defined in the Definitions Section.

Incidents reportable under this subsection (a) 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) Within 48 hours after the confirmed discovery of an incident, to the extent practicable, an operator must revise or confirm its initial telephonic notice required in paragraph (b) of this section with an estimate of the amount of product released, an estimate of the number of fatalities and injuries, and all other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages. If there are no changes or revisions to the initial report, the operator must confirm the estimates in its initial report.
- (d) In addition to the telephonic notice required in paragraph (b) of this section, notice ~~will~~ must also be made by telephone to (501) 682-5716 ~~during normal business hours Monday through Friday,~~ and electronically via email to PIR.MailBox@arkansas.gov and include the information listed in paragraph (b). Reports ~~outside normal business hours~~ will be made to PSO personnel in accordance with instructions issued by the PSO.
- ~~(e) 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.~~

§ 191.7 Report Submission Requirements

- (a) Each written report required by this part, with the exception of the "Safety-Related Condition Report", will be made to Pipeline Safety Office, Arkansas Public Service Commission, P. O. Box 400, Little Rock, Arkansas 72203-0400. These will be submitted in duplicate.
- (b) The Safety-Related Condition Reports required by §§ 191.23 and 191.25 will be submitted directly to: Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U. S. Department of Transportation, the Information Resources Manager, PHP-10, 1200 New Jersey Avenue, SE, Washington, DC 20590-0001. A copy of these reports must be submitted concurrently to the Pipeline Safety Office, Arkansas Public Service Commission.
- (c) *General.* Except as provided in paragraph (d) of this section, an operator must submit each report required by this part electronically to the Pipeline and Hazardous Materials Safety Administration at <http://portal.phmsa.dot.gov/pipeline> ~~http://portal.phmsa.dot.gov/pipeline~~ unless an alternative reporting method is authorized in accordance with paragraph (f) of this section.
- (d) *Exceptions.* An operator is not required to submit a safety-related condition report (§ 191.25) electronically.
- (e) *Safety Related Conditions.* An operator must submit concurrently to the Arkansas Pipeline Safety Office and to PHMSA a safety-related condition report required by §191.23 for intrastate pipeline transportation.
- (f) *Alternative Reporting Method.* If electronic reporting imposes an undue burden and hardship, an operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline ~~and Hazardous and Hazardous~~ Materials Safety Administration, PHP-20, 1200 New Jersey Avenue, SE, Washington, DC 20590. The request must describe the undue burden and

hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202-366-8075, or electronically to informationresourcesmanager@dot.gov or make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received.

- (g) *National Pipeline Mapping System (NPMS)*. An operator must provide the NPMS data to the address identified in the NPMS Operator Standards manual available at www.npms.phams.dot.gov or by contacting the PHMSA Geographic Information Systems Manager at (202) 366-4595.

§ 191.9 Distribution System: Incident Report

- (a) Each operator of a distribution pipeline system shall submit Department of Transportation Form PHMSA F7100.1 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).
- (a) 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.
- (b) Master meter operators are not required to submit an incident report as required by this section.

§ 191.11 Distribution System: Annual Report

- (a) Except as provided in paragraph (b) of this section, each operator of a distribution system shall submit an annual report for that system on Department of Transportation Form PHMSA F7100.1-1. This report shall be submitted for the preceding calendar year via email to APSC.PSORReports@arkansas.gov. The report must be submitted for the preceding calendar year received no later than March 15 of each year.
- (b) *Not* required. The annual report requirement in this section does not apply to a master meter system, a petroleum gas system that serves fewer than 100 customers from a single source, or an individual service line directly connected to a production pipeline or a gathering line other than a regulated gathering line as determined in § 192.8.

§ 191.12 [Removed and Reserved]

§ 191.13 Distribution Systems Reporting Transmission Pipelines: Transmission or Gathering Systems Reporting Distribution Pipelines

Each operator, primarily engaged in gas distribution, who also operates gas transmission or gathering pipelines shall submit separate reports for these pipelines as required by §§ 191.15 and 191.17. Each operator, primarily engaged in gas transmission or gathering, who also operates gas distribution pipelines shall submit separate reports for these pipelines as required by §§ 191.9 and 191.11.

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

- (a) *Pipeline Systems* –
 - (1) *Transmission, Offshore Gathering, or Regulated Onshore Gathering*. Each operator of a transmission, offshore gathering, or a regulated onshore gathering pipeline system or a regulated onshore gathering pipeline system subject to the jurisdiction of the Commission, shall must submit Department of Transportation (DOT) Form

PHMSA F7100.2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under § 191.5 ~~of this part.~~

(2) Reporting-regulated gathering. Each operator of a reporting-regulated gathering pipeline system must submit DOT Form PHMSA F 7100.2-2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under § 191.5 that occurs after May 16, 2022.

~~(b) LNG. Each operator of a liquefied natural gas plant or facility must submit DOT Form PHMSA F7100.3 as soon as practicable but not more than 30 days after detection of an incident required to be reported under § 191.5 of this part.~~

(c)(b) Underground natural gas storage facility. Each operator of a UNGSF must submit DOT Form PHMSA F7100.2 as soon as practicable but not more than 30 days after the detection of an incident required to be reported under § 191.5.

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

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

~~(a) Pipeline Systems —~~

~~(a)~~

(1) Transmission, offshore gathering, or regulated onshore Gathering. Each operator of a transmission system, offshore gathering, or a regulated onshore gathering pipeline system subject to the jurisdiction of the Commission shall must submit an annual report for that system on Department of Transportation a DOT Form PHMSA F 7100.2-1. This report shall be submitted for the preceding calendar year via email to APSC.PSORReports@arkansas.gov. The report must be received no later than March 15 of each year.

(2) This report must be submitted each year, not later than March 15, of each year. for the preceding calendar year.

Type R gathering. Beginning with an initial annual report submitted in March 2023 for the 2022 calendar year, each operator of a reporting-regulated gas gathering pipeline system must submit an annual report for that system on DOT Form PHMSA F 7100.2-3. This report shall be submitted for the preceding calendar year via email to APSC.PSORReports@arkansas.gov. The report must be received no later than March 15 of each year. This report must be submitted each year, not later than March 15, for the preceding calendar year.

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

Underground natural gas storage facility. Each operator of a UNGSF must submit an annual report through on DOT form PHMSA 7100.4-1. This report shall be submitted for the

~~preceding calendar year via email to APSC.PSORports@arkansas.gov. The report must be received no later than March 15 of each year. This report must be submitted each year, not later than March 15, for the preceding calendar year.~~

§ 191.21 OMB Control Number Assigned to Information Collection

This section displays the control number assigned by the Office of Management and Budget (OMB) to the information collection requirements in this part. The Paperwork Reduction Act requires agencies to display a current control number assigned by the Director of OMB for each agency information collection requirement.

OMB CONTROL NUMBER 2137-0522

Section of 49 CFR Part 191 where identified	Form No.
191.5	Telephonic and electronically via email.
191.9	PHMSA 7100.1, PHMSA 7100. 3.
191.11	PHMSA 7100.1-1, PHMSA 7100.3-1.
191.15	PHMSA 7100.2.
191.17	PHMSA 7100.2-1.
191.22	PHMSA 1000.1.

§ 191.22 National Registry of Pipeline and LNG operators

- (a) *OPID Request.* Effective January 1, 2012, each operator of a gas pipeline, gas pipeline facility, ~~LNG plant or LNG facility~~ must obtain from PHMSA an Operator Identification Number (OPID). An OPID is assigned to an operator for the pipeline or pipeline system for which the operator has primary responsibility. To obtain an OPID, an operator must complete an OPID Assignment Request DOT Form PHMSA F 1000.1 through the National Registry of Pipeline ~~and LNG Operators~~ in accordance with § 191.7.
- (b) *OPID validation.* An operator who has already been assigned one or more OPID by January 1, 2011, must validate the information associated with each OPID through the National Registry of Pipeline ~~and LNG Operators~~ at <http://portal.phmsa.dot.gov/pipeline>, and correct that information as necessary, no later than June 30, 2012.
- (c) *Changes.* Each operator of a gas pipeline, gas pipeline facility, ~~LNG plant or LNG facility~~ must notify PHMSA electronically through the National Registry of Pipeline ~~and LNG Operators~~ at <http://portal.phmsa.dot.gov/pipeline> of certain events.
 - (1) An operator must notify PHMSA of any of the following events not later than 60 days before the event occurs:
 - (i) Construction or any planned rehabilitation, replacement, modification, upgrade, update, or update of a facility, other than a section of line pipe that costs \$10 million or more. If 60-day notice is not feasible because of an emergency, an operator must notify PHMSA as soon as practicable;
 - (ii) Construction of 10 or more miles of a new or replacement pipeline;
 - ~~(iii) Construction of a new LNG plant or LNG facility.~~
 - ~~(iv)~~(iii) Construction of a new underground natural gas storage facility or the

abandonment, drilling or well workover (including replacement of wellhead, tubing, or a new casing) of an injection, withdrawal, monitoring, or observation well for an underground natural gas storage facility.

~~(v)~~(iv) Reversal of product flow direction when the reversal is expected to last more than 30 days. This notification is not required for pipeline systems already designed for bi-directional flow; or

~~(vi)~~(v) A pipeline converted for service under § 192.14 of this chapter, or a change in commodity as reported on the annual report as required by § 191.17.

(2) An operator must notify PHMSA of any of the following events not later than 60 days after the event occurs:

(i) A change in the primary entity responsible (i.e., with an assigned OPID) for managing or administering a safety program required by this part covering pipeline facilities operated under multiple OPIDs.

(ii) A change in the name of the operator;

(iii) A change in the entity (e.g., company, municipality) responsible for an existing pipeline, pipeline segment, or pipeline facility, ~~or LNG facility~~; or

(iv) The acquisition or divestiture of 50 or more miles of a pipeline or pipeline system subject to Part 192 of this subchapter; ~~or~~

~~(v) The acquisition or divestiture of an existing LNG plant or LNG facility subject to Part 193 of this subchapter.~~

(d) *Reporting.* An operator must use the OPID issued by PHMSA for all reporting requirements covered under this subchapter and for submissions to the National Pipeline Mapping System.

§ 191.23 Reporting Safety-Related Conditions

(a) Except as provided in paragraph (b) of this section, each operator shall report in accordance with § 191.25 the existence of any of the following safety-related conditions involving facilities in service:

(1) In the case of a pipeline ~~(other than an LNG facility)~~ that operates at a hoop stress of 20 percent or more of its specified minimum yield strength, general corrosion that has reduced the wall thickness to less than that required for the maximum allowable operating pressure, and localized corrosion pitting to a degree where leakage might result.

(2) In the case of a UNGSF, general corrosion that has reduced the wall thickness of any metal component to less than that required for the well's maximum operating pressure, or localized corrosion pitting to a degree where leakage might result.

~~(3) Unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability of a pipeline or the structural integrity or reliability of a UNGSF-an LNG facility that contains, controls or processes gas, or LNG.~~

~~(3) Any crack or other material defect that impairs the structural integrity or reliability of a UNGSF that contains controls or processes gas.~~

~~(4)~~

~~(4) Any crack or other material defect that impairs the structural integrity or reliability of~~

~~an LNG facility that contains controls or processes gas or LNG.~~

(5) Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of 20 percent or more of its specified minimum yield strength or the serviceability or the structural integrity of a UNGSF.

(6) Any malfunction or operating error that causes the pressure - plus the margin (build-up) allowed for operation of pressure limiting or control devices - to exceed either the maximum allowable operating pressure of a distribution or gathering line, the maximum well allowable operating pressure of an underground natural gas storage facility, ~~or the maximum allowable working pressure of an LNG facility that contains or processes gas or LNG. A leak in a pipeline or LNG facility that contains or processes gas or LNG that constitutes an emergency.~~

(7) A leak in a pipeline, or UNGSF, or LNG facility containing or processing gas or LNG that constitutes an emergency.

~~(8) Inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank.~~

~~(9)~~(8) Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline, or UNGSF, or an LNG facility that contains or processes gas ~~or LNG.~~

~~(10) [Reserved].~~

~~(11)~~(9) For transmission pipelines only, each exceedance of the maximum allowable operating pressure that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices as specified in the applicable requirements of §§ 192.201, 192.620(e), and 192.739. The reporting requirement of this paragraph (a)(9) is not applicable to gathering lines or, distribution lines, ~~or LNG facilities~~ (See paragraph (a)(~~56~~) of this section).

(b) A report is not required for any safety-related condition that:

(1) ~~Exists on a master meter system, a reporting-regulated gathering pipeline, or a customer-owned service line;~~ Exists on a master meter system, a reporting-regulated gathering pipeline, a Type C gas gathering pipeline with an outside diameter of 12.75 inches or less, a Type C gas gathering pipeline covered by the exception in § 192.9(f)(1) of this subchapter and therefore not required to comply with § 192.9(e)(2)(ii), or a customer-owned service line;

(2) Is an incident or results in an incident before the deadline for filing the safety-related condition report;

(3) Exists on a pipeline ~~(other than an LNG facility)~~ that is more than 220 yards (200 meters) from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway; or

(4) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report, except that reports are required for. ~~Notwithstanding this exception, a report must be filed for:~~

(i) Conditions under paragraph (a)(1) of this section, unless the condition is localized corrosion pitting on an effectively coated and cathodically protected pipeline; ~~and~~

- (ii) Any condition under paragraph (a)(9) of this section.
- (5) Exists on an UNGSF, where a well or wellhead is isolated, allowing the reservoir or cavern and all other components of the facility to continue to operate normally and without pressure restriction.

§ 191.25 Filing Safety-Related Condition Reports

- (a) Each report of a safety-related condition under § 191.23(a)(1) through (9) must be filed (received by the Associate Administrator) in writing within 5 working days (not including Saturday, Sunday, or Federal holidays) after the day a representative of an operator first determines that the condition exists, but not later than 10 working days after the day a representative of an operator discovers the condition. Separate conditions may be described in a single report if they are closely related. Reporting methods and report requirements are described in paragraph (c) of this section. Each report of a maximum allowable operating pressure exceedance meeting the requirements of criteria in § 191.23(a)(9) for a gas transmission pipeline must be filed (received by the Associate Administrator) in writing within 5 calendar days of the exceedance using the reporting methods and report requirements described in paragraph (c) of this section.
- (b) Reports must be filed by email to *InformationResourcesManager@dot.gov* or by facsimile to (202) 366-7128, and via email to *PIR.Mailbox@arkansas.gov*. For a report made pursuant to §191.23(a)(1) through (8), the report must be headed “Safety-Related Condition Report.” For a report made pursuant to § 191.23(a)(9), the report must be headed “Maximum Allowable Operating Pressure Exceedances.” All reports must provide the following information:
 - (1) Name, principal address, and operator identification number (OPID) of the operator.
 - (2) Date of report.
 - (3) Name, job title, and business telephone number of person submitting the report.
 - (4) Name, job title, and business telephone number of person who determined that the condition exists.
 - (5) Date condition was discovered, and date condition was first determined to exist.
 - (6) Location of condition, with reference to the State (and town, city, or county) or offshore site, and as appropriate, nearest street address, offshore platform, survey station number, milepost, landmark, or name of pipeline.
 - (7) Description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored.
 - (8) The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action.

§ 191.27 Status of Leaks

- (a) Each natural gas distribution operator shall submit to the Commission’s Pipeline Safety Office twice annually, no later than January 15th and July 15th, of each calendar year, a leak report.
- (b) The report shall include a caption identifying the report as “Leak Report” along with the name of the operator filing the report.

- (c) Each natural gas distribution operator shall provide on the leak report, the status of all known leaks within its system classified by type of leak, as Class I, II or III.
- (d) Each report shall identify and describe the status of each leak as follows:
 - (1) Identification Number for the leak; and
 - (2) All known leaks as of the beginning of each six-month period; and
 - (3) Those reported/found during the six-month period; and
 - (4) Date leak discovered; and
 - (5) The location of each leak, i.e. main, service, riser, meter, regulator station; and
 - (6) Those repaired during the six-month period with date of repair; and
 - (7) Those reported and awaiting repair at the end of the six-month period; and
 - (8) Pipe type, i.e. coated or bare steel, plastic, cast iron; and
 - (9) Leak cause, if known; and
 - (10) Method of how the utility became aware of the leak, i.e. leak survey, customer notification, operator employee.
- (e) The report shall include the signature, full name and title of the utility employee who prepared the report.
- (f) The above reporting requirement does not apply to master meter operators.

§ 191.29 National Pipeline Mapping System

- (a) Each operator of a gas transmission pipeline or liquefied natural gas facility must provide the following geospatial data to PHMSA for the pipeline or facility:
 - (1) Geospatial data, attributes, metadata and transmittal letter appropriate for use in the National Pipeline Mapping System. Acceptable formats and additional information are specified in the NPMS Operator Standards Manual available at <https://www.npms.phmsa.dot.gov/> or by contacting the PHMSA Geographic Information Systems Manager at (202) 366-4595;
 - (2) The name of and address for the operator; and
 - (3) The name and contact information of a pipeline company employee, to be displayed on a public Web site, who will serve as a contact for questions from the general public about the operator's NPMS data.
- (b) The information required in paragraph (a) of this section must be submitted each year, on or before March 15, representing assets as of December 31 of the previous year. If no changes have occurred since the previous year's submission, the operator must comply with the guidance provided in the NPMS Operator Standards manual available www.npms.phmsa.dot.gov or contact the PHMSA Geographic Information Systems Manager at (202) 366-4595.
- (c) This section does not apply to gathering pipelines.

APPENDIX A TO PART 191 PROCEDURE FOR DETERMINING REPORTING THRESHOLD

I. Property Damage Threshold Formula

Each year after calendar year 2021, the Administrator will publish a notice on PHMSA's website announcing the updates to the property damage threshold criterion that will take effect on July 1 of that year and will remain in effect until the June 30 of the next year. The property damage threshold used in the definition of an *Incident* at § 191.3 shall be determined in accordance with the following formula:

$$T_r = T_p \times \frac{CPI_r}{CPI_p}$$

Where:

T_r is the revised damage threshold,

T_p is the previous damage threshold,

CPI_r is the average Consumer Price Indices for all Urban Consumers (CPI-U) published by the Bureau of Labor Statistics each month during the most recent complete calendar year, and

CPI_p is the average CPI-U for the calendar year used to establish the previous property damage criteria.

PART 192 - TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM SAFETY STANDARDS

SUBPART A - GENERAL

§ 192.1 Scope

- (a) Part 192 prescribes minimum safety requirements for pipeline facilities and the transportation of gas within the State of Arkansas. Requirements of the Arkansas Gas Pipeline Code shall take precedence over any other requirements pertaining to construction, operation, and maintenance of gas facilities under the jurisdiction of the Arkansas Public Service Commission.
- (b) This part does not apply to gathering of gas through a pipeline that operates at less than 0 p.s.i.g. (0kPa), and through a pipeline that is not a regulated onshore gathering line (as determined in §192.8); however, it shall apply to the gathering, transmission or distribution of gas containing 100 or more parts-per-million of hydrogen sulfide from the custodial transfer meter through any pipeline, rural or non-rural, to and through any pipeline facility that removes hydrogen sulfide, except that portion of such a pipeline or pipeline facility that is located within the fenced boundary of a petroleum refinery.

§ 192.3 Definitions

As used in this part:

Abandoned means permanently removed from service.

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

Administrator means the Administrator of the Pipeline and Hazardous Materials Safety Administration or any person to whom authority in the matter concerned has been delegated by the U.S. Secretary of Transportation.

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

Business District means a location where gas mains are utilized to serve customers that are predominately commercial in nature and where the street and/or sidewalk paving generally extends from the centerline of a thoroughfare to the established building line on either side.

Change to a segment of pipeline means a physical change in the pipeline or significant changes in operating pressure.

Commission means, unless the context otherwise requires, the Arkansas Public Service Commission or any person or entity to whom the Commission has delegated authority in the matter concerned.

Close interval survey means a series of closely and properly spaced pipe-to-electrolyte potential measurements taken over the pipe to assess the adequacy of cathodic protection or to identify locations where a current may be leaving the pipeline that may cause corrosion and for the purpose of quantifying voltage (IR) drops other than those across the structure electrolyte boundary, such as when performed as a current interrupted, depolarized, or native survey.

Composite Materials means materials used to make pipe or components manufactured with a

combination of either steel and/or plastic, or both, and with a reinforcing material to maintain its circumferential or longitudinal strength.

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

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

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

Distribution center means the initial point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption, as opposed to customers who purchase it for resale, for example:

- (1) At a metering location;
- (2) A pressure reduction location; or
- (3) Where there is a reduction in the volume of gas, such as a lateral off a transmission line.

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

Dry gas or dry natural gas means gas above its dew point and without condensed liquids.

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.

Engineering critical assessment (ECA) means a documented analytical procedure based on fracture mechanics principles, relevant material properties (mechanical and fracture resistance properties), operating history, operational environment, in-service degradation, possible failure mechanisms, initial and final defect sizes, and usage of future operating and maintenance procedures to determine the maximum tolerable sizes for imperfections based upon the pipeline segment maximum allowable operating pressure.

Entirely replaced onshore transmission pipeline segments means, for the purposes of §§ 192.179 and 192.634, where 2 or more miles, in the aggregate, of onshore transmission pipeline have been replaced within any 5 contiguous miles of pipeline within an 24-month period. This definition does not apply to any gathering line.

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

Gathering Line means a pipeline that transports gas from a current production facility to a transmission line or main.

Hard spot means an area on steel pipe material with a minimum dimension greater than two inches (50.8 mm) in any direction and hardness greater than or equal to Rockwell 35 HRC (Brinell 327 HB or Vickers 345 HV¹⁰).

High Pressure Distribution System means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer.

Key Valves means shut off valves in a distribution system or transmission line which may be necessary to isolate segments of a system or line for emergency purposes.

In-line inspection (ILI) means an inspection of a pipeline from the interior of the pipe using an inspection tool also called intelligent or smart pigging. This definition includes tethered and self-propelled inspection tools.

In-line inspection tool or instrumented internal inspection device means an instrumented device or vehicle that uses a non-destructive testing technique to inspect the pipeline from the inside in order to identify and characterize flaws to analyze pipeline integrity; also known as an intelligent or smart pig.

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

Listed Specification means a specification listed in Section I of Appendix B to Part 192.

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

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

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

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

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

Mobile Home Park means two or more mobile homes located on a contiguous tract of land.

Moderate consequence area means:

- (1) An onshore area that is within a potential impact circle, as defined in § 192.903, containing either:
 - (i) Five or more buildings intended for human occupancy; or
 - (ii) Any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, as defined in the Federal Highway Administration's *Highway Functional Classification Concepts, Criteria and Procedures, Section 3.1* (see: https://www.fhwa.dot.gov/planning/processes/statewide/related/highway_functional_classifications/fcauab.pdf), and that does not meet the definition of high consequence area, as defined in § 192.903.
- (2) The length of the moderate consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle containing either 5 or more buildings intended for human occupancy; or any portion of the paved surface, including shoulders, of any designated interstate, freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, to the outermost edge of the last contiguous potential impact circle that contains either 5 or more buildings intended for human occupancy, or any portion of the paved surface, including shoulders, of any

designated interstate, freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes.

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

Notification of potential rupture means the notification to, or observation by, an operator of indicia identified in § 192.635 of a potential unintentional or uncontrolled release of a large volume of gas from a pipeline. This definition does not apply to any gathering line.

Operator means a person who:

- (1) Engages in the transportation of gas; or
- (2) Operates a distribution system within a mobile home park, public housing authority, or multiple building complex if:
 - (A) The system:
 - (i) Is not owned, nor the responsibility of a public or municipal utility; and
 - (ii) Is used to transport gas from a master meter or a public/municipal utility main to consumers who may or may not be metered; and
 - (B) The gas distributed is not consumed solely by the owner/operator.

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

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 p.s.i.g. (1434 kPa) gage at 100°F (38°C).

Petroleum Refinery means an industrial or manufacturing facility or plant primarily engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants or other products through the processing of petroleum crude oil that is subject to:

- (A) The federal Environmental Protection Agency Standards of Performance for New Stationary Sources set forth in Subpart GGG of 40 CFR part 60 or successor regulations;
- (B) The federal *Environmental* Protection Agency Chemical Accident Prevention Provisions set forth in Subparts, A, B, D, E, F, G, and H of 40 CFR Part 68 or successor regulations; and
- (C) The federal Occupational Safety and Health Administration Regulations governing process safety management of highly hazardous chemicals set forth in 29 CFR §1910.119 or successor regulations.

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

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

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

Pipeline Facilities includes without limitation, new and existing pipe, pipe rights-of-way, and any equipment, facility or building used in the transportation of gas or the treatment of gas during the course of transportation of gas.

Private Line System means a natural gas pipeline or pipeline system that is not a master meter system; is not owned by, nor the responsibility of a public or municipal utility; is used to transport gas that is not consumed solely by the owner/operator from a public or municipal utility meter to consumers who may or may not be metered.

Production Facilities includes without limitation, piping or equipment used in the production, extraction, recovery, lifting, stabilization, separation or treatment of natural gas or associated storage or measurement from the wellhead to a meter where the gas is transferred to a custodian other than the well operator for gathering or transport, commonly known as a “custodial transfer meter.”

Production Process means the extraction of gas from the geological source of supply to the surface of the earth, thence through the lines and equipment used to treat, compress and measure the gas between the wellhead and the meter where it is either sold or delivered to a custodian other than *the well operator* for gathering and transport to a place of sale, sometimes called “custodial transfer meter.”

Rupture-mitigation valve (RMV) means an automatic shut-off valve (ASV) or a remote-control valve (RCV) that a pipeline operator uses to minimize the volume of gas released from the pipeline and to mitigate the consequences of a rupture. This definition does not apply to any gathering line.

Service Line means a distribution line that transports gas from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer’s piping, whichever is further downstream, or at the connection to customer piping if there is no meter.

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

SMYS means specific minimum yield strength, and is:

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

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.

Test Failure means a break or rupture that occurs during strength proof testing of transmission or gathering lines that are of such magnitude as to require repair before continuation of the test.

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

- (1) Transports gas from a gathering line or storage facility to a gas distribution center, storage facility or large volume customer that is not down-stream from a gas distribution center;
- (2) Operates at a hoop stress of 20 percent or more of SMYS; ~~or~~

(3) Transports gas within a storage field; or

(4) Is voluntarily designated by the operator as a transmission pipeline.

NOTE: A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

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

Underground natural gas storage facility (UNGSF) means a gas pipeline facility that stores natural gas underground incidental to the transportation of natural gas, including:

(1) (i) A depleted hydrocarbon reservoir;

(ii) An aquifer reservoir; or

(iii) A solution-mined salt cavern.

(2) In addition to the reservoir or cavern, a UNGSF includes injection, withdrawal, monitoring, and observation wells; wellbores and downhole components; wellheads and associated wellhead piping; wing-valve assemblies that isolate the wellhead from connected piping beyond the wing-valve assemblies; and any other equipment, facility, right-of-way, or building used in the underground storage of natural gas.

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

Welding operator means a person who operates machine or automatic welding equipment.

Weak link means a device or method used when pulling polyethylene pipe, typically through methods such as horizontal directional drilling, to ensure that damage will not occur to the pipeline by exceeding the maximum tensile stresses allowed.

Wrinkle bend means a bend in the pipe that:

(1) Was formed in the field during construction such that the inside radius of the bend has one or more ripples with:

(i) An amplitude greater than or equal to 1.5 times the wall thickness of the pipe, measured from peak to valley of the ripple; or

(ii) With ripples less than 1.5 times the wall thickness of the pipe and with a wrinkle length (peak to peak) to wrinkle height (peak to valley) ratio under 12.

(2)

(i) If the length of the wrinkle bend cannot be reliably determined, then **wrinkle bend** means a bend in the pipe where $(h/D)*100$ exceeds 2 when S is less than 37,000 psi (255 MPa), where $(h/D)*100$ exceeds $(47000-S)/10,000 + 1$ for psi [$(324-S)/69 + 1$ for MPa] when S is greater than 37,000 psi (255 MPa) but less than 47,000 psi (324 MPa), and where $(h/D)*100$ exceeds 1 when S is 47,000 psi (324 MPa) or more.

(ii) Where:

(A) D = Outside diameter of the pipe, in. (mm);

(B) h = Crest-to-trough height of the ripple, in. (mm); and An operator of an onshore steel transmission pipeline must develop a remedial action plan and apply for any necessary permits within 6 months of

~~completing the assessment that identified the deficiency. An operator must repair any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dB μ V for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within 6 months of the assessment, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after the receipt of permits.~~

(C) S = Maximum operating hoop stress, psi (S/145, MPa).

§ 192.5 Class Locations

- (a) This section classifies pipeline locations for the purposes of this part. The following criteria apply to classifications under this section.
 - (1) A "class location unit" is an area that extends 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline.
 - (2) Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.
- (b) Except as provided in paragraph (c) of this section, pipeline locations are classified as follows:
 - (1) A Class 1 location is any class location unit that has 10 or fewer buildings intended for human occupancy.
 - (2) A Class 2 location is any class location unit that has more than 10 but fewer than 46 buildings intended for human occupancy.
 - (3) A Class 3 location is:
 - (i) Any class location unit that has 46 or more buildings intended for human occupancy; or
 - (ii) An area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)
 - (4) A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.
- (c) The boundaries of Class locations 2, 3, and 4 may be adjusted as follows:
 - (1) A Class 4 location ends 220 yards (200 meters) from the nearest building with four or more stories above ground.
 - (2) When all buildings intended for human occupancy within a Class 2 or 3 location are in a single cluster, the class location ends 220 yards (200 meters) from the nearest building in the cluster.
- (d) An operator must have records that document the current class location of each gas transmission pipeline segment and that demonstrate how the operator determined each current class location in accordance with this section.

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

(a) (a) Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. ~~The materials listed in this section have the full force of law.~~ All approved incorporation by reference (IBR) material is available for inspection at the Pipeline and Hazardous Materials Safety Administration (PHMSA) 1200 New Jersey Avenue SE, Washington, DC 20590; 202-366-4046; <https://www.phmsa.dot.gov/pipeline/regs> and ~~at the National Archives and Records Administration (NARA).~~ ~~is available from the sources listed in the remaining paragraphs of this section.~~ It is also available for inspection at the National Archives and Records Administration (NARA). ~~For information on the availability of this material at NARA, email fedreg.legal@nara.gov fr.inspection@nara.gov, or go to www.archives.gov/federal-register/cfr/ibr-locations.html or email fr.inspection@nara.gov.~~ It is also available from the sources in the following paragraphs of this section. Contact PHMSA at: Office of Pipeline Safety, Pipeline and Hazardous Material Safety Administration, 1200 New Jersey Avenue SE, Washington, DC 20590; 202-366-4046; www.phmsa.dot.gov/pipeline/regs. For information on the availability of this material at NARA, visit www.archives.gov/federal-register/cfr/ibr-locations.html or email fr.inspection@nara.gov. It is also available from the sources in the following paragraphs of this section. ~~Availability of standards incorporated by reference. All of the materials incorporated by reference are available for inspection from several sources, including the following:-~~

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

~~(ii) The National Archives and Records Administration (NARA). For information on the availability of this material at NARA, email fedreg.legal@nara.gov or go to the NARA Web site at: <http://www.archives.gov/federal-register/code-of-federal-regulations/ibr-locations.html>.~~

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

(b) American Petroleum Institute (API), 200 Massachusetts Ave. NW, Suite 1100, Washington, DC 20001, and phone: 202-682-8000, website: <https://www.api.org>.

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

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

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

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

(5) API Recommended Practice 1162, "Public Awareness Programs for Pipeline

- Operators,” 1st edition, December 2003, (API RP 1162), IBR approved for § 192.616(a), (b), and (c).
- (6) API Recommended Practice 1165, “Recommended Practice for Pipeline SCADA Displays,” First edition, January 2007, (API RP 1165), IBR approved for § 192.631(c).
 - (7) ~~API Specification 5L, “Specification for Line Pipe” 45th edition, effective July 1, 2013, (API Spec 5L), IBR approved for §§ 192.55(e); 192.112(a), (b), (d), (e); 192.113; and Item I, Appendix B to Part 192. API Specification 5L, Line Pipe, 46th edition, April 2018, including Errata 1 (May 2018), (API Spec 5L); IBR approved for §§ 192.55(e); 192.112(a), (b), (c), (d), and (e); 192.113; appendix B to part 192.~~
 - (8) ~~ANSI/API Specification 6D, “Specification for Pipeline Valves,” edition, effective October 1, 2008, including Errata 1 (June 2008), Errata 2 (November 2008), Errata 3 (February 2009), Errata 4 (April 2010), Errata 5 (November 2010), Errata 6 (August 2011) Addendum 1 (October 2009), Addendum 2 (August 2011), and Addendum 3 (October 2012), (ANSI/API Spec 6D), IBR approved for § 192.145(a). API Specification 6D, Specification for Pipeline and Piping Valves, 24th edition, August 2014, including Errata 1 through 10 (October 2014 through July 2021), Addendum 1 (March 2015), and Addendum 2 (June 2016), (API Spec 6D); IBR approved for § 192.145(a).~~
 - (9) ~~API Standard 1104, “Welding of Pipelines and Related Facilities,” 20th edition, October 2005, including errata/addendum (July 2007) and errata 2 (2008), (API Std 1104), IBR approved for §§ 192.225(a); 192.227(a); 192.229(c); 192.241(c); and Item II, Appendix B. API Standard 1104, Welding of Pipelines and Related Facilities, 21st edition, September 2013, including Errata 1 through 5 (April 2014 through September 2018), Addendum 1 (2014), and Addendum 2 (2016), (API Std 1104); IBR approved for §§ 192.225(a); 192.227(a); 192.229(b) and (c); 192.241(c); appendix B to part 192.~~
 - (10) ~~API Standard 1163, “In-Line Inspection Systems Qualification,” Second edition, April 2013, Reaffirmed August 2018, (API STD 1163), IBR approved for § 192.493. API Recommended Practice 1170, “Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage,” First edition, July 2015 (API RP 1170), IBR approved for § 192.12.~~
 - ~~(10)(11)~~ API Recommended Practice 1171, “Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs,” First edition, September 2015, (API RP 1171), IBR approved for § 192.12
- (c) ~~ASME International~~ American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016, 800-843-2763; ~~(U.S./Canada),~~ <http://www.asme.org/>. ~~email: CustomerCare@asme.org; website: www.asme.org/.~~
- (1) (ASME/ANSI B16.1-2005, “Gray Iron Pipe Flanges and Flanged Fittings: (Classes 25, 125, and 250),” August 31, 2006, (ASME/ANSI B16.1), IBR approved for § 192.147(c).
 - (2) ASME/ANSI B16.5-2003, “Pipe Flanges and Flanged Fittings,” October 2004, (ASME/ANSI B16.5), IBR approved for §§ 192.147(a), ~~192.279, and~~ 192.607(f).
 - (3) ASME B16.40-2008, “Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems,” March 18, 2008, approved by ANSI, (ASME B16.40-2008), IBR approved for Item I, Appendix B to Part 192.

- (4) ASME/ANSI B31G-1991 (Reaffirmed 2004, “Manual for Determining the Remaining Strength of Corroded Pipelines,” 2004, (ASME/ANSI B31G), IBR approved for §§ 192.485(c), 192.632(a), 192.712(b), and 192.933(a).
- (5) ~~ASME/ANSI B31.8-2007, “Gas Transmission and Distribution Piping Systems,” November 30, 2007, (ASME/ANSI B31.8), IBR approved for §§ 192.112(b) and 192.619(a).~~ ASME B31.8-2018, Gas Transmission and Distribution Piping Systems, Issued November 20, 2018, (ASME B31.8); IBR approved for §§ 192.112(b); 192.619(a).
- (6) ASME/ANSI B31.8S-2004, “Supplement to B31.8 on Managing System Integrity of Gas Pipelines,” approved January 14, 2005, 2004, (ASME/ANSI B31.8S-2004-2004), IBR approved for §§ 192.903 note to Potential impact radius; 192.907 introductory text, (b); 192.911 introductory text, (i), (k), (l), (m); 192.913(a), (b), (c)(d); 192.917 (a), (b), (c), and (d), (e); 192.903 not to potential impact radius; 192.907 introductory text and (b); 192.911 introductory text, (i), and (k) through (m); 192.913(a) through (c); 192.917(a) through (e); 192.921(a); 192.923(b); 192.925(b); 192.927(b), and (c); 192.929(b); 192.933(c), and (d); 192.935 (a), and (b); 192.937(c); 192.939(a); and 192.945(a). 192.714(d); 192.933.(d).
- (7) ~~[Removed and Reserved]~~ ASME B31.8S-2018, Managing System Integrity of Gas Pipelines, Issued November 28, 2018, (ASME B31.8S); IBR approved for §§ 192.13(d); 192.714(c); 192.903 note to Potential impact radius; 192.907 introductory text and (b); 192.911 introductory text, (i), and (k) through (m); 192.913(a) through (c); 192.917(a) through (e); 192.921(a); 192.923(b); 192.925(b); 192.933(c); 192.935(b); 192.937(c); 192.939(a); 192.945(a).
- (8) ~~ASME Boiler & Pressure Vessel Code, Section VIII, Division 1 “Rules for Construction of Pressure Vessels,” 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 1), IBR approved for §§ 192.153.(a), (b), (d), and 192.165(b).~~ ASME B36.10M-2018, Welded and Seamless Wrought Steel Pipe, Issued October 12, 2018, (ASME B36.10M); IBR approved for § 192.279.
- (9) ASME Boiler & Pressure Vessel Code, Section VIII, Division 2 “Rules, Rules for Construction of Pressure Vessels” 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 2), IBR approved for §§ 192.153(b), (d); and 192.165(b).
- (10) ASME Boiler & Pressure Vessel Code, Section IX: “Qualification Standard for Welding and Brazing Procedures, Welders, Brazers, and Welding and Brazing Operators,” 2007 edition, July 1, 2007, ASME BPVC, Section IX, IBR approved for §§ 192.225(a); 192.227(a); and Item II, Appendix B to Part 192.
- (11) API Standard 1163, “In-Line Inspection Systems Qualification,” Second edition, April 2013, Reaffirmed August 2018, (API STD 1163), IBR approved for § 192.493.
- (d) American Society for Nondestructive Testing (ASNT), P.O. Box 28518, 1711 Arlingate Lane, Columbus, OH 43228, phone: 800-222-2768, website: <https://www.asnt.org/>.
- (1) ANSI/ASNT ILI-PQ-2005 (2010), “In-line Inspection Personnel Qualification and Certification,” Reapproved October 11, 2010, (ANSI/ASNT-PQ), IBR approved for § 192.493.
- (2) [Reserved]
- (2) ~~ASME/ANSI B16.5-2003, “Pipe Flanges and Flanged Fittings,” October 2004, (ASME/ANSI B16.5), IBR approved for §§ 192.147(a), 192.279, and 192.607(f).~~

- (e) ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, website: <http://astm.org>; ASTM International (ASTM), 100 Barr Harbor Drive, P.O. Box C700, West Conshohocken, PA 19428; phone: (610) 832-9585; email: service@astm.org; website: www.astm.org.
- (1) ASTM A53/A53M-10, "Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless," approved October 1, 2010, (ASTM A53/A53M), IBR approved for § 192.113; and Item II, Appendix B to Part 192. ASTM A53/A53M-20, Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless, approved July 1, 2020, (ASTM A53/A53M); IBR approved for § 192.113; appendix B to part 192.
 - (2) ASTM A106/A106M-10, "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service," approved October 1, 2010, (ASTM A106/A106M), IBR approved for § 192.113; and Item I, Appendix B to Part 192. ASTM A106/A106M-19A, Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service, approved November 1, 2019, (ASTM A106/A106M); IBR approved for § 192.113; appendix B to part 192.
 - (3) ASTM A333/A333M-11, "Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service," approved April 1, 2011, (ASTM A333/A333M), IBR approved for § 192.113; and Item I, Appendix B to Part 192. ASTM A333/A333M-18, Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service and Other Applications with Required Notch Toughness, approved November 1, 2018, (ASTM A333/A333M); IBR approved for § 192.113; appendix B to part 192.
 - (4) ASTM A372/A372M-10, "Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels," approved October 1, 2010, (ASTM A372/A372M), IBR approved for § 192.177(b).
 - (5) ASTM A381-96 (reapproved 2005), "Standard Specification for Metal-Arc-Welded Steel Pipe for Use with High-Pressure Transmission Systems," approved October 1, 2005, (ASTM A381), IBR approved for § 192.113; and Item I, Appendix B to Part 192. ASTM A381/A381M-18, Standard Specification for Metal-Arc-Welded Carbon or High-Strength Low-Alloy Steel Pipe for Use with High-Pressure Transmission Systems, approved November 1, 2018, (ASTM A381); IBR approved for § 192.113; appendix B to part 192.
 - (6) ASTM A578/A578M-96 (reapproved 2001), "Standard Specification for Straight-Beam Ultrasonic Examination of Plain and Clad Steel Plates for Special Applications," (ASTM A578/A578M), IBR approved for § 192.112(c).
 - (7) ASTM A671/A671M-10, "Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperature," approved April 1, 2010, (ASTM A671/A671M), IBR approved for § 192.113; and Item I, Appendix B to Part 192. ASTM A671/A671M-20, Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures, approved March 1, 2020, (ASTM A671/A671M); IBR approved for § 192.113; appendix B to part 192.
 - (8) ASTM A672/A672M-09, "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperature," approved October 1, 2009, (ASTM A672/A672M), IBR approved for § 192.113 and Item I, Appendix B to Part 192.

- (9) ~~ASTM A691/A691M-09, Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High approved October 1, 2009, (ASTM A691/A691M), IBR approved for § 192.113 and Item I, Appendix B to Part 192. ASTM A691/A691M-19, Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures, approved November 1, 2019, (ASTM A691/A691M); IBR approved for § 192.113; appendix B to part 192.~~
- (10) ASTM D638-03, "Standard Test Method for Tensile Properties of Plastics," 2003, (ASTM D638), IBR approved for § 192.283(a) and (b).
- (11) ASTM D2513-18a, "Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings," approved August 1, 2018, (ASTM D2513), IBR approved for Item I, Appendix B to Part 192.
- (12) ASTM D2517-00, "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings," (ASTM D 2517), IBR approved for §§ 192.191(a); 192.281(d); 192.283(a); and Item I, Appendix B to Part 192.
- (13) ASTM D2564-12, "Standard Specification for Solvent Cements for Poly (Vinyl Chloride)(PVC) Plastic Piping Systems," August 1, 2012, (ASTM D2564- 12), IBR approved for §192.281(b)(2).
- (14) ASTM F1055- 98 (Reapproved 2006), "Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing," March 1, 2006, (ASTM F1055-98 (2006)), IBR approved for § 192.283(a), Item I, Appendix B to Part 192.
- (15) ASTM F1055-98 (Reapproved 2006), "Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing," March 1,2006, ASTM F1055-98 (2006)), IBR approved for §192.283(a), Item I Appendix B to Part 192 ASTM F1924-12), "Standard Specification for Plastic Mechanical Fittings for Use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing, " April 1, 2012 (ASTM F1924-12), IBR approved for Item 1 Appendix B to Part 192.
- (16) ASTM F1948-12, (Standard Specification for Metallic Mechanical Fittings for Use on Outside Diameter Controlled Thermoplastic Gas Distribution Pipe and Tubing," April 1, 2012, (ASTM F1948-12), IBR approved for Item I, Appendix B to Part 192.
- (17) ASTM F1973-13, "Standard Specification for Factory Assembled Anodeless Risers and Transition Fittings in Polyethylene (PE) and Polyamide 11 (PA11) and Polyamide 12 (PA12) Fuel Gas Distribution Systems," May 1, 2013, (ASTM F1973-13), IBR approved for §192.204(b); and Item I, Appendix B to Part 192.
- (18) ASTM F2145-13, 'Standard Specification for Polyamide 11 (PA11) and Polyamide 12 (PA12) Mechanical Fittings for Use on Outside Diameter Controlled Polyamide 11 and Polyamide 12 Pipe and Tubing," May 1, 2013, (ASTM F2145-13), IBR approved for Item 1, Appendix B to Part 192.
- (19) ASTM F2600-09, "Standard Specification for Electrofusion Type Polyamide-11 Fittings for Outside Diameter Controlled Polyamide-11 Pipe an Tubing," April 1, 2009, (ASTM F 2600-09) IBR approved for Item I, Appendix B to Part 192.
- (20) ASTM F2620-19,"Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings," approved February 1, 2019, (ASTM F2620), IBR approved for §§192.281(c) and 192.285(b).
- (21) ASTM 2767-12, "Specification for Electrofusion Type Polyamide-12 Fittings for Outside Diameter Controlled Polyamide-12 Pipe and Tubing for Gas Distribution." Oct 15, 2012, (ASTM F2767-12), IBR approved for Item I, Appendix B to Part 192.

- (22) ASTM F2785-12, "Standard Specification for Polyamide 12 Gas Pressure Pipe, Tubing and Fittings," Aug. 1 2012, (ASTM F2785-12), IBR approved for Item 1, Appendix B to Part 192.
 - (23) ASTM F2817-10, "Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair," Feb. 1, 2010 (ASTM F2817-10), IBR approved for Item 1, Appendix B to Part 192.
 - (24) ASTM F2945-12a "Standard Specification for Polyamide 11 Gas Pressure Pipe, Tubing and Fittings," Nov 27, 2012 (ASTM F2945-12a), IBR approved for Item I, Appendix B to Part 192.
- ~~(f) Gas Technology Institute (GTI), formerly the Gas Research Institute (GRI), 1700 S. Mount Prospect Road, Des Plaines, IL 60018, phone: 847-768-0500, Web site: www.gastechnology.org.~~
- ~~(1) (GRI 02/0057 (2002) "Internal Corrosion Direct Assessment of Gas Transmission Pipelines Methodology," (GRI 02/0057), IBR approved for § 192.927(c).~~
 - ~~(2) [Reserved].~~
- ~~(f) [Reserved]~~
- (g) Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park St. NE., Vienna, VA 22180, phone: 703-281-6613, ~~Web site: [email: info@msshq.org](mailto:info@msshq.org);~~ ~~website: <http://www.msshq.org/>.~~
 - ~~(1) MSS SP-44-2010, Standard Practice, "Steel Pipeline Flanges," 2010 edition, (including Errata (May 20, 2011)), (MSS SP-44), IBR approved for § 192.147(a). [ANSI/MSS SP-44-2019, Steel Pipeline Flanges, published April 2020, \(MSS SP-44\); IBR approved for § 192.147\(a\).](#)~~
 - (2) [Reserved]
 - (h) NACE International (NACE), 1440 South Creek Drive, Houston, TX 77084: phone: 281-228-6223 or 800-797-6223 Web site: <http://www.nace.org/Publications/>.
 - (1) NACE Standard Practice 0102-~~2010~~ "In-Line Inspection of Pipelines," Revised 2010-03-13, (NACE SP0102), IBR approved for §§ 192.150(a) and 192.493.
 - ~~(2) [NACE SP0204-2008, Standard Practice, "Stress Corrosion Cracking \(SCC\) Direct Assessment Methodology," reaffirmed September 18, 2008, \(NACE SP0204\); IBR approved for §§ 192.923\(b\); 192.929\(b\) introductory text, \(b\)\(1\) through \(3\), \(b\)\(5\) introductory text, and \(b\)\(5\)\(i\).](#)~~
 - ~~(3) [NACE SP0206-2006, Standard Practice, "Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas \(DG-ICDA\)." approved December 1, 2006, \(NACE SP0206\), IBR approved for §§ 192.923\(b\); 192.927\(b\), \(c\) introductory text, and \(c\)\(1\) through \(4\).](#)~~
 - ~~(4) [ANSI/NACE SP0502-2010, Standard Practice, "Pipeline External Corrosion Direct Assessment revised June 24, 2010, \(NACE SP0502\), IBR approved for §§ 192.923\(b\); 192.925\(b\); 192.931\(d\); 192.935\(b\) and 192.939\(a\).](#)~~
 - (i) National Fire Protection Association (NFPA), 1 Batterymarch Park, Quincy, Massachusetts 02169, phone: (617) 984-7275; website: www.nfpa.org.
 - (1) NFPA-30 (2012), "Flammable and Combustible Liquids Code," 2012 edition, June 20, 2011, including Errata 30-12-1 (September 27, 2011) and Errata 30-12-2 (November 14, 2011), (NFPA-30), IBR approved for § 192.735(b).

- (2) ~~NFPA 58 (2004), "Liquefied Petroleum Gas Code (LP-Gas Code)," (NFPA 58), IBR approved for § 192.11(a), (b), and (c). NFPA 58, Liquefied Petroleum Gas Code, 2020 edition, effective August 25, 2019, (NFPA 58); IBR approved for § 192.11.~~
 - (3) ~~NFPA 59 (2004), "Utility LP-Gas Plant Code," (NFPA 59), IBR approved for § 192.11(a), (b), and (c). NFPA 59, Utility LP-Gas Plant Code, 2018 edition, effective September 6, 2017, (NFPA 59); IBR approved for § 192.11.~~
 - (4) ~~NFPA 70 (2011), "National Electrical Code," 2011 edition, issued August 5, 2010, (NFPA 70), IBR approved for §§ 192.163(e); and 192.189(e). NFPA 70, National Electrical Code (NEC), 2017 edition, effective August 24, 2016, (NFPA 70); IBR approved for §§ 192.163(e); 192.189(c).~~
- (j) Pipeline Research Council International, Inc. (PRCI), c/o Technical Toolboxes, 3801 Kirby Drive, Suite 520, P.O. Box 980550, Houston, TX 77098, phone: 713-630-0505, toll free: 866-866-6766, Web site: <http://www.ttoolboxes.com/>. (Contract number PR3-805.)
- (1) AGA, Pipeline Research Committee Project, PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe," (December 22, 1989), (PRCI PR-3-805 (R-STRENG)), IBR approved for §§ 192.485(c); 192.632(a); 192.712(b); 192.933(a) and (d).
 - (2) [Reserved]
- (k) Plastics Pipe Institute, Inc. (PPI), 105 Decker Court, Suite 825 Irving TX 75062, phone: 469-499-1044, <http://www.plasticpipe.org/>.
- (1) PPI TR-3/2012, HDB/HDS/PDB/SDB/MRS/CRS, Policies, "Policies and Procedures for Developing Hydrostatic Design Basis (HDB), Hydrostatic Design Stresses (HDS), Pressure Design Basis (PDB), Strength Design Basis (SDB), Minimum Required Strength (MRS) Ratings, and Categorized Required Strength (CRS) for Thermoplastic Piping Materials or Pipe," updated November 2012, (PPI TR-3/2012), IBR approved for §192.121.
 - (2) PPI TR-4, HDB/HDS/SDB/MRS, Listed Materials, "PPI Listing of Hydrostatic Design Basis (HDB), Hydrostatic Design Stress (HDS), Strength Design Basis (SDB), Pressure Design Basis (PDB) and Minimum Required Strength (MRS) Rating For Thermoplastic Piping Materials or Pipe," updated March 2011, (PPI TR-4/2012), IBR approved for § 192.121.

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

- (a) An operator must use API RP 80 (incorporated by reference, see § 192.7), to determine if an onshore pipeline (or part of a connected series of pipelines) is an onshore gathering line. The determination is subject to the limitations listed below. After making this determination, an operator must determine if the onshore gathering line is a regulated onshore gathering line under paragraph (b) of this section.
- (1) The beginning of gathering, under section 2.2(a)(1) of API RP 80, may not extend beyond the furthest downstream point in a production operation as defined in section 2.3 of API RP 80. This furthest downstream point does not include equipment that can be used in either production or transportation, such as separators or dehydrators, unless that equipment is involved in the processes of “production and preparation for transportation or delivery of hydrocarbon gas” within the meaning of “production operation.”
 - (2) The endpoint of gathering, under section 2.2(a)(1)(A) of API RP 80, may not extend beyond the first downstream natural gas processing plant, unless the operator can demonstrate, using sound engineering principles, that gathering extends to a further downstream plant.
 - (3) If the endpoint of gathering, under section 2.2(a)(1)(C) of API RP 80, is determined by the commingling of gas from separate production fields, the fields may not be more than 50 miles from each other, unless the Administrator finds a longer separation distance is justified in a particular case (see 49 CFR § 190.9).
 - (4) The endpoint of gathering, under section 2.2(a)(1)(D) of API RP 80, may not extend beyond the furthest downstream compressor used to increase gathering line pressure for delivery to another pipeline.
 - (5) For new, replaced, relocated, or otherwise changed gas gathering pipelines installed after May 16, 2022, the endpoint of gathering under sections 2.2(a)(1)(E) and 2.2.1.2.6 of API RP 80 (incorporated by reference, see § 192.7) – also known as “incidental gathering” – may not be used if the pipeline terminates 10 or more miles downstream from the furthest downstream endpoint as defined in paragraphs 2.2(a)(1)(A) through (a)(1)(D) of API RP 80 (incorporated by reference, see § 192.7) and this section. If an “incidental gathering” pipeline is 10 miles or more in length, the entire portion of the pipeline that is designated as an incidental gathering line under 2.2(a)(1)(E) and 2.2.1.2.6 of API RP 80 shall be classified as a transmission pipeline subject to all applicable regulations in this chapter for transmission pipelines.
- ~~(b) — For purposes of § 192.9 “regulated onshore gathering line” means:~~
- ~~(1) — Each onshore gathering line (or segment of onshore gathering line) with a feature described in the second column that lies in an area described in the third column; and~~
 - ~~(2) — As applicable, additional lengths of line described in the fourth column to provide a safety buffer:~~
- (b) Each operator must determine and maintain for the life of the pipeline records documenting the methodology by which it calculated the beginning and end points of each onshore gathering pipeline it operates, as described in the second column of table 1 to paragraph (c)(2) of this section, by:

- (1) November 16, 2022, or before the pipeline is placed into operation, whichever is later; or
 - (2) An alternative deadline approved by the Pipeline and Hazardous Materials Safety Administration (PHMSA). The operator must notify PHMSA and State or local pipeline safety authorities, as applicable, no later than 90 days in advance of the deadline in paragraph (b)(1) of this section. The notification must be made in accordance with § 192.18 and must include the following information:
 - i. Description of the affected facilities and operating environment;
 - ii. Justification for an alternative compliance deadline; and
 - iii. Proposed alternative deadline.
- (c) For purposes of part 191 of this chapter and § 192.9, the term “regulated onshore gathering pipeline” means:
- (1) Each Type A, Type B, or Type C onshore gathering pipeline (or segment of onshore gathering pipeline) with a feature described in the second column of table 1 to paragraph (c)(2) of this section that lies in an area described in the third column; and
 - (2) As applicable, additional lengths of pipeline described in the fourth column to provide a safety buffer:

Table 1 to Paragraph (c)(2)

Type	Feature	Area	Additional Safety Buffer
A	-Metallic and the MAOP produces a hoop stress of 20 percent or more of SMYS	Class 2, 3, or 4 location (see § 192.5)	None.
	-If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part		
	-Non-metallic and the MAOP is more than 125 psig (862 kPa)		
B	-Metallic and the MAOP produces a hoop stress of less than 20 percent of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part	Area 1. Class 3 or 4 location. Area 2. An area within a Class 2 location the operator determines by using any of the following three methods:	If the gathering pipeline is in Area 2(b) or 2(c), the additional lengths of line extend upstream and downstream from the area to a point where the line is at least 150 feet (45.7 m) from the

	-Non-metallic and the MAOP is 125 psig (862 kPa) or less	(a) A Class 2 location; (b) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1 mile (1.6 km) of pipeline and including more than 10 but fewer than 46 dwellings; or (c) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1000 feet (305 m) of pipeline and including 5 or more dwellings	nearest dwelling in the area. However, if a cluster of dwellings in Area 2(b) or 2(c) qualifies a pipeline as Type B, the Type B classification ends 150 feet (45.7m) from the nearest dwelling in the cluster.
C	Outside diameter greater than or equal to 8.625 inches and any of the following: -Metallic and the MAOP produces a hoop stress of 20 percent or more of SMYS; -If the stress level is unknown, segment is metallic and the MAOP is more than 125 psig (862 kPa); or -Non-metallic and the MAOP is more than 125 psig (862 kPa)	Class 1 location	None.
R	-All other onshore gathering lines	Class 1 and Class 2 locations	None.

- (3) A Type R gathering line is subject to reporting requirements under part 191 of this chapter but is not a regulated onshore gathering line under this part.
- (4) For the purpose of identifying Type C lines in table 1 to paragraph (c)(2) of this section, if an operator has not calculated MAOP consistent with the methods at § 192.619(a) or (c)(1), the operator must either:
- (i) Calculate MAOP consistent with the methods at § 192.619(a) or (c)(1); or

- (ii) Use as a substitute for MAOP the highest operating pressure to which the segment was subjected during the preceding 5 operating years.

§ 192.9 What requirements apply to gathering lines?

- (a) *Requirements.* An operator of a gathering line must follow the safety requirements of this part as prescribed by this section.
- (b) *Offshore lines.* An operator of an offshore gathering line must comply with requirements of this part applicable to transmission lines, except the requirements in §§ 192.13(d), 192.150, 192.285(e), 192.319(d) through (g), 192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.465(d), 192.485(c), 192.493, 192.506, 192.607, 192.613(c), 192.619(e), 192.624, 192.710, 192.712, and 192.714 and in subpart O of this part.
- (c) *Type A lines.* An operator of a Type A regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in §§ 192.13(d), 192.150, 192.285(e), 192.319(d) through (g), 192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c), 192.493, 192.506, 192.607, 192.613(c), 192.619(e), 192.624, 192.710, 192.712, and 192.714 and in subpart O of this part. However, operators of a Type A regulated onshore gathering line in a Class 2 location may demonstrate compliance with subpart N by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks. Further, operators of Type A regulated onshore gathering lines are exempt from the requirements of §§ 192.179(e) through (g), 192.610, 192.617(b) through (d), 192.634, 192.635, 192.636, and 192.745(c) through (f). Lastly, operators of Type A regulated onshore gathering lines are exempt from the requirements of § 192.615 (but an operator of a Type A regulated onshore gathering line must comply with the requirements of 49 CFR 192.615, effective as of October 4, 2022).
- (d) *Type B lines.* An operator of a Type B regulated onshore gathering line must comply with the following requirements:
- (1) If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this part applicable to transmission lines, except the requirements in—Compliance with §§ 192.67, 192.127, 192.179(e) and 192.179(f), 192.205, 192.227(c), 192.285(e), 192.319(d) through (g), and 192.506, 192.634, and 192.636 is not required.
 - (2) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines except the requirements in §§ 192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c), and 192.493;
 - (3) If the pipeline contains plastic pipe or components, the operator must comply with all applicable requirements of this part for plastic pipe components;
 - (4) Carry out a damage prevention program under § 192.614;
 - (5) Establish a public education program under § 192.616;
 - (6) Establish the MAOP of the line under § 192.619(a), (b), and (c);
 - (7) Install and maintain line markers according to the requirements for transmission lines in § 192.707; and

- (8) Conduct leakage surveys in accordance with the requirements for transmission lines in § 192.706 using leak detection equipment, and promptly repair hazardous leaks in accordance with § 192.703(c).
- (e) Type C lines. The requirements for Type C gathering lines are as follows:
- (1) An operator of a Type C onshore gathering line with an outside diameter greater than or equal to 8.625 inches must comply with the following requirements:
- (i) Except as provided in paragraph (h) of this section for pipe and components made with composite materials, the design, installation, construction, initial inspection, and initial testing of a new, replaced, relocated, or otherwise changed Type C gathering line, must be done in accordance with the requirements in subparts B through G and J of this part applicable to transmission lines. Compliance with §§ 192.67, 192.127, 192.179(e), and 192.179(f), 192.205, 192.227(c), 192.285(e), 192.319(d) through (g), and 192.506, 192.634, and 192.636 is not required.
 - (ii) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines except for §§192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c), and 192.493;
 - (iii) Carry out a damage prevention program under § 192.614;
 - (iv) Develop and implement procedures for emergency plans in accordance with § 192.615, effective as of October 4, 2022;
 - (v) Develop and implement a written public awareness program in accordance with 192.616;
 - (vi) Install and maintain line markers according to the requirements for transmission lines in §192.707; and
 - (vii) Conduct leakage surveys in accordance with the requirements for transmission lines in § 192.706 using leak-detection equipment, and promptly repair hazardous leaks in accordance with § 192.703(c).
- (2) An operator of a Type C onshore gathering line with outside diameter greater than 12.75 inches must comply with the requirements paragraph (e)(1) of this section and the following:
- (i) If the pipeline contains plastic pipe, the operator must comply with all applicable requirements of this part for plastic pipe or components. This does not include pipe and components made of composite materials that incorporate plastic in the design; and
 - (ii) Establish the MAOP of the pipeline under § 192.619(a) or (c) and maintain records used to establish the MAOP for the life of the pipeline.
- (f) Exceptions.
- (1) Compliance with paragraphs (e)(1)(ii), (v), (vi), and (vii) and (e)(2)(i) and (ii) of this section is not required for pipeline segments that are 16 inches or less in outside diameter if one of the following criteria are met:
- (i) Method 1. The segment is not located within a potential impact circle containing a building intended for human occupancy or other impacted site. The potential impact circle must be calculated as specified in § 192.903.

except that a factor of 0.73 must be used instead of 0.69. The MAOP used in this calculation must be determined and documented in accordance with paragraph (e)(2)(ii) of this section.

- (ii) Method 2. The segment is not located within a class location unit (see § 192.5) containing a building intended for human occupancy or other impacted site.
- (2) Paragraph (e)(1)(i) of this section is not applicable to pipeline segments 40 feet or shorter in length that are replaced, relocated, or changed on a pipeline existing on or before May 16, 2022.
- (3) For purposes of this section, the term “building intended for human occupancy or other impacted site” means any of the following:
 - (i) Any building that may be occupied by humans, including homes, office buildings, factories, outside recreation areas, plant facilities, etc.;
 - (ii) A small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12 month period (the days and weeks need not be consecutive); or
 - (iii) Any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes.

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

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

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

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

Requirement	Compliance deadline
Control corrosion according to Subpart I requirements for transmission	April 15, 2009.

~~Carry out a damage prevention program under § 192.614.
Establish MAOP under § 192.619.
Install and maintain line markers under § 192.707.
Establish a public education program under § 192.616.
Other provisions of this part as required by paragraph (c) of this section-
Type A lines.~~

~~October 15, 2007.
October 15, 2007.
April 15, 2008.
April 15, 2008.
April 15, 2009.~~

- (3) If, after April 14, 2006, a change in class location or increase in dwelling density causes an onshore gathering line to be a regulated onshore gathering line, the operator has 1 year for Type B lines and 2 years for Type A lines after the line becomes a regulated onshore gathering line to comply with this section.
- (4) If a Type C gathering pipeline existing on or before May 16, 2022, was not previously subject to this part, an operator must comply with the applicable requirements of this section, except for paragraph (h) of this section, on or before:
- (i) May 16, 2023; or
 - (ii) An alternative deadline approved by PHMSA. The operator must notify PHMSA and State or local pipeline safety authorities, as applicable, not later than 90 days in advance of the deadline in paragraph (b)(1) of this section. The notification must be made in accordance with § 192.18 and must include a description of the affected facilities and operating environment, the proposed alternative deadline for each affected requirement, the justification for each alternative compliance deadline, and actions the operator will take to ensure the safety of affected facilities.
- (5) If, after May 16, 2022, a change in class location, an increase in dwelling density, or an increase in MAOP causes a pipeline to become a Type C gathering pipeline, or causes a Type C gathering pipeline to become subject to additional Type C requirements (see paragraph (f) of this section), the operator has 1 year after the pipeline becomes subject to the additional requirements to comply with this section.
- (h) Composite Materials. Pipe and components made with composite materials not otherwise authorized for use under this part may be used on Type C gathering pipelines if the following requirements are met:
- (1) Steel and plastic pipe and components must meet the installation, construction, initial inspection, and initial testing requirements in subparts B through G and J of this part applicable to transmission lines.
 - (2) Operators must notify PHMSA in accordance with § 192.18 at least 90 days prior to installing new or replacement pipe or components made of composite materials otherwise not authorized for use under this part in a Type C gathering pipeline. The notifications required by this section must include a detailed description of the pipeline facilities in which pipe or components made of composite materials would be used, including:
 - (i) The beginning and end points (stationing by footage and mileage with latitude and longitude coordinates) of the pipeline segment containing composite pipeline material and the counties and States in which it is located;

- (ii) A general description of the right-of-way including high consequence areas, as defined in § 192.905;
 - (iii) Relevant pipeline design and construction information including the year of installation, the specific composite material, diameter, wall thickness, and any manufacturing and construction specifications for the pipeline;
 - (iv) Relevant operating information, including MAOP, leak and failure history, and the most recent pressure test (identification of the actual pipe tested, minimum and maximum test pressure, duration of test, any leaks and any test logs and charts) or assessment results;
 - (v) An explanation of the circumstances that the operator believes make the use of composite pipeline material appropriate and how the design, construction, operations, and maintenance will mitigate safety and environmental risks;
 - (vi) An explanation of procedures and tests that will be conducted periodically over the life of the composite pipeline material to document that its strength is being maintained;
 - (vii) Operations and maintenance procedures that will be applied to the alternative materials. These include procedures that will be used to evaluate and remediate anomalies and how the operator will determine safe operating pressures for composite pipe when defects are found;
 - (viii) An explanation of how the use of composite pipeline material would be in the public interest; and
 - (ix) A certification signed by a vice president (or equivalent or higher officer) of the operator's company that operation of the applicant's pipeline using composite pipeline material would be consistent with pipeline safety.
- (3) Repairs or replacements using materials authorized under this part do not require notification under this section.

§ 192.11 Petroleum Gas Systems

- ~~(a) — Each plant that supplies petroleum gas by pipeline to a natural gas distribution system must meet the requirements of this part and NFPA 58 and 59 (incorporated by reference, see § 192.7).~~
- ~~(b) — Each pipeline system subject to this part that transports only petroleum gas or petroleum gas/air mixtures must meet the requirements of this part and NFPA 58 and 59 (incorporated by reference, see § 192.7).~~
- ~~(c) — In the event of a conflict between this part and NFPA 58 and 59 (incorporated by reference, see § 192.7), NFPA 58 and 59 prevail.~~
- ~~(a) — Each plant that supplies petroleum gas by pipeline to a natural gas distribution system must meet the requirements of this part and NFPA 58 or NFPA 59 (both incorporated by reference, see § 192.7), based on the scope and applicability statements in those standards.~~
- ~~(b) — Each pipeline system subject to this part that transports only petroleum gas or petroleum gas/air mixtures must meet the requirements of this part and NFPA 58 or NFPA 59 (both incorporated by reference, see § 192.7), based on the scope and applicability statements in those standards.~~

- ~~(c) In the event of a conflict between this part and NFPA 58 or NFPA 59 (both incorporated by reference, see § 192.7), NFPA 58 or NFPA 59 shall prevail if applicable based on the scope and applicability statements in those standards.~~

§192.12 Underground natural gas storage facilities

Underground natural gas storage facilities (“UNGSFs”), as defined in §192.3, are not subject to any requirements of this part aside from this section.

(a) Salt cavern UNGSFs.

- (1) Each UNGSF that uses a solution-mined salt cavern for natural gas storage and was constructed after March 13, 2020, must meet all the provisions of API RP 1170 (incorporated by reference, see § 192.7), the provisions of section 8 of API RP 1171 (incorporated by reference, see § 192.7) that are applicable to the physical characteristics and operations of a solution-mined salt cavern UNGSF, and paragraphs (c) and (d) of this section prior to commencing operations.
- (2) Each UNGSF that uses a solution-mined salt cavern for natural gas storage and was constructed between July 18, 2017, and March 13, 2020, must meet all the provisions of API RP 1170 (incorporated by reference, see § 192.7) and paragraph (c) of this section prior to commencing operations, and must meet all the provisions of section 8 of API RP 1171 (incorporated by reference, see § 192.7) that are applicable to the physical characteristics and operations of a solution-mined salt cavern UNGSF, and paragraph (d) of this section, by March 13, 2021.
- (3) Each UNGSF that uses a solution-mined salt cavern for natural gas storage and was constructed on or before July 18, 2017, must meet the provisions of API RP 1170 (incorporated by reference, see § 192.7), sections 9, 10, and 11, and paragraph (c) of this section, by January 18, 2018, and must meet all provisions of section 8 of API RP 1171 (incorporated by reference, see § 192.7) that are applicable to the physical characteristics and operations of a solution-mined salt cavern UNGSF, and paragraph (d) of this section, by March 13, 2021.

(b) Depleted hydrocarbon and aquifer reservoir UNGSFs.

- (1) Each UNGSF that uses a depleted hydrocarbon reservoir or an aquifer reservoir for natural gas storage and was constructed after July 18, 2017, must meet all provisions of API RP 1171 (incorporated by reference, see § 192.7), and paragraphs (c) and (d) of this section, prior to commencing operations.
 - (2) Each UNGSF that uses a depleted hydrocarbon reservoir or an aquifer reservoir for natural gas storage and was constructed on or before July 18, 2017, must meet the provisions of API RP 1171 (incorporated by reference, see § 192.7), sections 8, 9, 10, and 11, and paragraph (c) of this section, by January 18, 2018, and must meet all provisions of paragraph (d) of this section by March 13, 2021.
- (c) Procedural manuals. Each operator of a UNGSF must prepare and follow for each facility one or more manuals of written procedures for conducting operations, maintenance, and emergency preparedness and response activities under paragraphs (a) and (b) of this section. Each operator must keep records necessary to administer such procedures and review and update these manuals at intervals not exceeding 15 months, but at least once each calendar year. Each operator must keep the appropriate parts of these manuals accessible at locations where UNGSF work is being performed. Each operator must have written procedures in place before commencing operations or beginning an activity not yet

implemented.

(d) Integrity management program—

(1) Integrity management program elements. The integrity management program for each UNGSF under this paragraph (d) must consist, at a minimum, of a framework developed under API RP 1171 (incorporated by reference, see § 192.7), section 8 (“Risk Management for Gas Storage Operations”), and that also describes how relevant decisions will be made and by whom. An operator must make continual improvements to the program and its execution. The integrity management program must include the following elements:

- (i) A plan for developing and implementing each program element to meet the requirements of this section;
- (ii) An outline of the procedures to be developed;
- (iii) The roles and responsibilities of UNGSF staff assigned to develop and implement the procedures required by this paragraph (d);
- (iv) A plan for how staff will be trained in awareness and application of the procedures required by this paragraph (d);
- (v) Timelines for implementing each program element, including the risk analysis and baseline risk assessments; and
- (vi) A plan for how to incorporate information gained from experience into the integrity management program on a continuous basis.

(2) Integrity management baseline risk-assessment intervals. No later than March 13, 2024, each UNGSF operator must complete the baseline risk assessments of all reservoirs and caverns, and at least 40% of the baseline risk assessments for each of its UNGSF wells (including wellhead assemblies), beginning with the highest-risk wells, as identified by the risk analysis process. No later than March 13, 2027, an operator must complete baseline risk assessments on all its wells (including wellhead assemblies). Operators may use prior risk assessments for a well as a baseline (or part of the baseline) risk assessment in implementing its initial integrity management program, so long as the prior assessments meet the requirements of API RP 1171 (incorporated by reference, see § 192.7), section 8, and continue to be relevant and valid for the current operating and environmental conditions. When evaluating prior risk-assessment results, operators must account for the growth and effects of indicated defects since the time the assessment was performed.

(3) Integrity management re-assessment intervals. The operator must determine the appropriate interval for risk assessments under API RP 1171 (incorporated by reference, see § 192.7), subsection 8.7.1, and this paragraph (d) for each reservoir, cavern, and well, using the results from earlier assessments and updated risk analyses. The re-assessment interval for each reservoir, cavern, and well must not exceed seven years from the date of the baseline assessment for each reservoir, cavern, and well.

(4) Integrity management procedures and recordkeeping. Each UNGSF operator must establish and follow written procedures to carry out its integrity management program under API RP 1171 (incorporated by reference, see § 192.7), section 8 (“Risk Management for Gas Storage Operations”), and this paragraph (d). The operator must also maintain, for the useful life of the UNGSF, records that

demonstrate compliance with the requirements of this paragraph (d). This includes records developed and used in support of any identification, calculation, amendment, modification, justification, deviation, and determination made, and any action taken to implement and evaluate any integrity management program element.

§ 192.13 What general requirements apply to pipelines regulated under this part?

- (a) No person may operate a segment of pipeline listed in the first column of paragraph (a)(3) of this section that is readied for service after the date in the second column, unless:
 - (1) The pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this part; or
 - (2) The pipeline qualifies for use under this part according to the requirements in § 192.14.
 - (3) The compliance deadlines are as follows:

Pipeline	Date
(i) Offshore gathering pipeline	July 31, 1977
(ii) Regulated onshore gathering pipeline to which this part did not apply until April 14, 2006	March 15, 2007
(iii) Regulated onshore gathering pipeline to which this part did not apply until May 16, 2022	May 16, 2023
(iv) All other pipelines	March 12, 1971

- (b) No person may operate a segment of pipeline listed in the first column of this paragraph (b) that is replaced, relocated, or otherwise changed after the date in the second column of this paragraph (b), unless the replacement, relocation or change has been made according to the requirements in this part.

Pipeline	Date
(1) Offshore gathering pipeline	July 31, 1977
(2) Regulated onshore gathering pipeline to which this part did not apply until April 14, 2006	March 15, 2007
<u>(3) Regulated onshore gathering pipeline to which this part did not apply until May 16, 2022</u>	<u>May 16, 2023</u>
(4) All other pipelines	November 12, 1970

- (c) Each operator shall maintain, modify as appropriate, and follow the plans, procedures, and programs that it is required to establish under this part.
- (d) Each operator of an onshore gas transmission pipeline must evaluate and mitigate, as necessary, significant changes that pose a risk to safety or the environment through a management of change process. Each operator of an onshore gas transmission pipeline must develop and follow a management of change process, as outlined in ASME B31.8S, section 11 (incorporated by reference, see § 192.7), that addresses technical, design,

physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline or processes, whether permanent or temporary. A management of change process must include the following: reason for change, authority for approving changes, analysis of implications, acquisition of required work permits, documentation, communication of change to affected parties, time limitations, and qualification of staff. For pipeline segments other than those covered in subpart O of this part, this management of change process must be implemented by February 26, 2024. The requirements of this paragraph (d) do not apply to gas gathering pipelines. Operators may request an extension of up to 1 year by submitting a notification to PHMSA at least 90 days before February 26, 2024, in accordance with § 192.18. The notification must include a reasonable and technically justified basis, an up-to-date plan for completing all actions required by this section, the reason for the requested extension, current safety or mitigation status of the pipeline segment, the proposed completion date, and any needed temporary safety measures to mitigate the impact on safety.

§ 192.14 Conversion to Service Subject to this Part

- (a) A steel pipeline previously used in service not subject to this part qualifies for use under this part if the operator prepares and follows a written procedure to carry out the following requirements:
 - (1) The design, construction, operation, and maintenance history of the pipeline must be reviewed and, where sufficient historical records are not available, appropriate tests must be performed to determine if the pipeline is in a satisfactory condition for safe operation.
 - (2) The pipeline right-of-way, all above-ground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline.
 - (3) All known unsafe defects and conditions must be corrected in accordance with this part.
 - (4) The pipeline must be tested in accordance with Subpart J of this part to substantiate the maximum allowable operating pressure permitted by Subpart L of this part.
- (b) Each operator must keep for the life of the pipeline a record of investigations, tests, repairs, replacements, and alterations made under the requirements of paragraph (a) of this section.
- (c) An operator converting a pipeline from service not previously covered by this part must notify PHMSA 60 days before the conversion occurs as required by § 191.22 of this chapter.

§ 192.15 Rules of Regulatory Construction

- (a) As used in this part:
 - Includes** means "including but not limited to."
 - May** means "is permitted to" or "is authorized to."
 - May not** means "is not permitted to" or "is not authorized to."
 - Shall** is used in the mandatory and imperative sense.

- (b) In this part:
 - (1) Words importing the singular include the plural;
 - (2) Words importing the plural include the singular; and
 - (3) Words importing the masculine gender include the feminine.

§ 192.16 Customer Notification

- (a) This section applies to each operator of a service line who does not maintain the customer's buried piping up to entry of the first building downstream, or, if the customer's buried piping does not enter a building, up to the principal gas utilization equipment or the first fence (or wall) that surrounds that equipment. For the purpose of this section, "customer's buried piping" does not include branch lines that serve yard lanterns, pool heaters, or other types of secondary equipment. Also, "maintain" means monitor for corrosion according to § 192.465 if the customer's buried piping is metallic, survey for leaks according to § 192.723, and if an unsafe condition is found, shut off the flow of gas, advise the customer of the need to repair the unsafe condition, or repair the unsafe condition.
- (b) Each operator shall notify each customer once in writing of the following information:
 - (1) The operator does not maintain the customer's buried piping.
 - (2) If the customer's buried piping is not maintained, it may be subject to the potential hazards of corrosion and leakage.
 - (3) Buried gas piping should be-
 - (i) Periodically inspected for leaks;
 - (ii) Periodically inspected for corrosion if the buried piping is metallic; and
 - (iii) Repaired if any unsafe condition is discovered.
 - (4) When excavating near buried gas piping, the piping should be located in advance, and the excavation done by hand.
 - (5) The operator (if applicable), plumbing contractors, and heating contractors can assist in locating, inspecting, and repairing the customer's buried piping.
- (c) Each operator shall notify each customer not later than August 14, 1996, or 90 days after the customer first receives gas at a particular location, whichever is later. However, operators of master meter systems may continuously post a general notice in a prominent location frequented by customers.
- (d) Each operator must make the following records available for inspection by the Administrator or a State agency participating under 49 U.S.C. 60105 or 60106:
 - (1) A copy of the notice currently in use; and
 - (2) Evidence that notices have been sent to customers within the previous 3 years.

§ 192.17 Filing of Operation, Inspection, and Maintenance Plan

Each operator shall file with the Pipeline Safety Office of the Arkansas Public Service Commission (PSO) a plan for operation, inspection, and maintenance of each pipeline facility which the operator owns or operates. In addition, each change to this plan must be filed with the PSO within 20 days after the change is made. Once filed, this plan becomes a part of these standards as though

incorporated and must be followed by the operator.

§ 192.18 How to Notify PHMSA

- (a) An operator must provide any notification required by this part by -
 - (1) Sending the notification by electronic mail to *InformationResourcesManager@dot.gov*; or
 - (2) Sending the notification by mail to ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd Floor, E22-321, 1200 New Jersey Ave. SE, Washington, DC 20590.
- (b) An operator must also notify the appropriate State or local pipeline safety authority when an applicable pipeline segment is located in a State where OPS has an interstate agent agreement, or an intrastate applicable pipeline segment is regulated by that State.
- (c) Unless otherwise specified, if ~~an operator submits, pursuant to the notification is made pursuant to § 192.8(b)(2), § 192.9(g)(4)(ii) and (h), §192.13, §192.179, § 192.319, § 192.461, § 192.461(g), § 192.506(b), § 192.607(e)(4), § 192.607(e)(5), §192.619(e)(2) § 192.624(e)(2)(iii), § 192.624(e)(6), § 192.632(b)(3), §192.634, § 192.636, § 192.710(e)(7), § 192.712(d)(3)(iv), § 192.712(e)(2)(i)(E), § 192.714, § 192.745, §192.917, § 192.921(a)(7), §192.927, § 192.933, §192.927(b), or § 192.937(e)(7)~~ a notification for use of a different integrity assessment method, analytical method, compliance period, sampling approach, pipeline material, or technique (*i.e.*, “other technology”) or “alternative equivalent technology”) than otherwise that differs from that prescribed in those sections, that notification must be submitted to ~~the operator must notify~~ PHMSA for review at least 90 days in advance of using the other method, approach, compliance timeline, or technique. ~~technology~~. An operator may proceed to use the other method, approach, compliance timeline, or technique ~~technology~~ 91 days after ~~submission of~~ submitting the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing the operator that PHMSA objects to the ~~proposal proposed use of other technology~~ or that PHMSA requires additional time and/or more information to conduct its review.

SUBPART B - MATERIALS

§ 192.51 Scope

This subpart prescribes minimum requirements for the selection and qualification of pipe and components for use in pipelines.

§ 192.53 General

Materials for pipe and components must be:

- (a) Able to maintain the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated;
- (b) Chemically compatible with any gas that they transport and with any other material in the pipeline with which they are in contact; and
- (c) Qualified in accordance with the applicable requirements of this subpart.

§ 192.55 Steel Pipe

- (a) New steel pipe is qualified for use under this part if:
 - (1) It was manufactured in accordance with a listed specification;
 - (2) It meets the requirements of:
 - (i) Section II of Appendix B to this part; or
 - (ii) If it was manufactured before November 12, 1970, either Section II or III of Appendix B to this part; or
 - (3) It is used in accordance with paragraph (c) or (d) of this section.
- (b) Used steel pipe is qualified for use under this part if:
 - (1) It was manufactured in accordance with a listed specification, and it meets the requirements of paragraph II-C of Appendix B to this part;
 - (2) It meets the requirements of:
 - (i) Section II of Appendix B to this part; or
 - (ii) It was manufactured before November 12, 1970, either Section II or III of Appendix B to this part; or
 - (3) It has been used in an existing line of the same or higher pressure and meets the requirements of paragraph II-C of Appendix B to this part; or
 - (4) It is used in accordance with paragraph (c) of this section.
- (c) New or used steel pipe may be used at a pressure resulting in a hoop stress of less than 6,000 p.s.i. (41 MPa) where no close coiling or close bending is to be done, if visual examination indicates that the pipe is in good condition and that it is free of split seams and other defects that would cause leakage. If it is to be welded, steel pipe that has not been manufactured to a listed specification must also pass the weldability tests prescribed in paragraph II-B of Appendix B to this part.
- (d) Steel pipe that has not been previously used may be used as replacement pipe in a segment of pipeline if it has been manufactured prior to November 12, 1970, in accordance with the same specification as the pipe used in constructing that segment of pipeline.
- (e) New steel pipe that has been cold expanded must comply with the mandatory provisions of API Spec 5L (incorporated by reference, see § 192.7).

§ 192.57 [Removed and Reserved]

§ 192.59 Plastic Pipe

- (a) New plastic pipe is qualified for use under this part if:
 - (1) It is manufactured in accordance with a listed specification;
 - (2) It is resistant to chemicals with which contact may be anticipated; and
 - (3) It is free of visible defects.
- (b) Used plastic pipe is qualified for use under this part if:
 - (1) It was manufactured in accordance with a listed specification;
 - (2) It is resistant to chemicals with which contact may be anticipated;
 - (3) It has been used only in gas service;

- (4) Its dimensions are still within the tolerances of the specification to which it was manufactured; and
- (5) It is free of visible defects.
- (c) For the purpose of paragraphs (a)(1) and (b)(1) of this section, when a pipe of a diameter included in a listed specification is impractical to use, pipe of a diameter between the sizes included in a listed specification may be used if it:
 - (1) Meets the strength and design criteria required of pipe included in the listed specification; and
 - (2) Is manufactured from plastic compounds which meet the criteria for material required of pipe included in that listed specification.
- (d) Rework and/or regrind material is not allowed in plastic pipe produced after March 6, 2015, used under this part.

§ 192.61 [Removed and Reserved]

§ 192.63 Marking of Materials

- (a) Except as provided in paragraph (d) and (e) of this section, each valve, fitting, length of pipe, and other component must be marked as prescribed in the specification or standard to which it was manufactured.
- (b) Surfaces of pipe and components that are subject to stress from internal pressure may not be field die stamped.
- (c) If any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations.
- (d) Paragraph (a) of this section does not apply to items manufactured before November 12, 1970, that meet all of the following:
 - (1) The item is identifiable as to type, manufacturer, and model.
 - (2) Specifications or standards giving pressure, temperature, and other appropriate criteria for the use of items are readily available.
- (e) All plastic pipe and components must also meet the following requirements:
 - (1) All markings on plastic pipe prescribed in the listed specification and the requirements of paragraph(e)(2) of this section must be repeated at intervals not exceeding two feet.
 - (2) Plastic pipe and components manufactured after December 31, 2019, must be marked in accordance with the listed specification.
 - (3) All physical markings on plastic pipelines prescribed in the listed specification and paragraph(e)(2) of this section must be legible until the time of installation.
- (f) Operators shall reidentify pipe if specification markings are obliterated during the coating and/or wrapping process. This reidentification is not necessary if pipe is immediately installed in a system.

§ 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 install pipe having an outer diameter to wall thickness ratio of 70 to 1,

or more, that is transported by railroad unless the transportation is performed by API RP 5L1 (incorporated by reference, see § 192.7).

- (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 RP 5LW (incorporated by reference, see § 192.7).
- (c) *Truck.* 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 truck unless the transportation is performed in accordance with API RP 5LT (incorporated by reference, see § 192.7).

§192.67 Records: Material properties.

- (a) For steel transmission pipelines installed after July 1, 2020, an operator must collect or make, and retain for the life of the pipeline, records that document the physical characteristics of the pipeline, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition of materials for pipe in accordance with §§192.53 and 192.55. Records must include tests, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed.
- (b) For steel transmission pipelines installed on or before July 1, 2020, if operators have records that document tests, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition in accordance with §§192.53 and 192.55, operators must retain such records for the life of the pipeline.
- (c) For steel transmission pipeline segments installed on or before July 1, 2020, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of §192.624 according to the terms of that section.

§192.69 Storage and Handling of Plastic Pipe and Associated Components.

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

SUBPART C - PIPE DESIGN

§ 192.101 Scope

This subpart prescribes the minimum requirements for the design of pipe.

§ 192.103 General

Pipe must be designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipe after installation.

§ 192.105 Design Formula for Steel Pipe

- (a) The design pressure for steel pipe is determined in accordance with the following formula:

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

- P** = Design pressure in pounds per square inch (kPa) gage.
- S** = Yield strength in pounds per square inch (kPa) determined in accordance with § 192.107.
- D** = Nominal outside diameter of the pipe in inches (millimeters).
- T** = Nominal wall thickness of the pipe in inches (millimeters). If this is unknown, it is determined in accordance with § 192.109. Additional wall thickness required for concurrent external loads in accordance with § 192.103 may not be included in computing design pressure.
- F** = Design factor determined in accordance with § 192.111.
- E** = Longitudinal joint factor determined in accordance with § 192.113.
- T** = Temperature derating factor determined in accordance with § 192.115.
- (b) If steel pipe that has been subjected to cold expansion to meet the SMYS is subsequently heated, other than by welding or stress relieving as a part of welding, the design pressure is limited to 75 percent of the pressure determined under paragraph (a) of this section if the temperature of the pipe exceeds 900°F (482°C) at any time or is held above 600°F (316°C) for more than 1 hour.

§ 192.107 Yield Strength (S) for Steel Pipe

- (a) For pipe that is manufactured in accordance with a specification listed in Section I of Appendix B of this part, the yield strength to be used in the design formula in § 192.105 is the SMYS stated in the listed specification, if that value is known.
- (b) For pipe that is manufactured in accordance with a specification not listed in Section I of Appendix B to this part or whose specification or tensile properties are unknown, the yield strength to be used in the design formula in § 192.105 is one of the following:
- (1) If the pipe is tensile tested in accordance with Section II-D of Appendix B to this part, the lower of the following:
- (i) 80 percent of the average yield strength determined by the tensile tests.
- (ii) The lowest yield strength determined by the tensile tests, but not more than 52,000 p.s.i.
- (2) If the pipe is not tensile tested as provided in Subparagraph (b)(1) of this paragraph, 24,000 p.s.i. (165 MPa).

§ 192.109 Nominal Wall Thickness (t) for Steel Pipe

- (a) If the nominal wall thickness for steel pipe is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end.
- (b) However, if the pipe is of uniform grade, size, and thickness and there are more than 10 lengths, only 10 percent of the individual lengths, but not less than 10 lengths, need be measured. The thickness of the lengths that are not measured must be verified by applying a gauge set to the minimum thickness found by the measurement. The nominal wall thickness to be used in the design formula in § 192.105 is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness used may not be more than 1.14 times the smallest

measurement taken on pipe less than 20 inches (508 millimeters) in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe 20 inches (508 millimeters) or more in outside diameter.

§ 192.111 Design Factor (F) for Steel Pipe

- (a) Except as otherwise provided in paragraphs (b), (c), and (d) of this section, the design factor to be used in the design formula in § 192.105 is determined in accordance with the following table:

Class	Design
<u>Location</u>	<u>Factor</u>
(F) 1	0.72
2.....	0.60
3.....	0.50
4.....	0.40

- (b) A design factor of 0.60 or less must be used in the design formula in § 192.105 for steel pipe in Class 1 locations that:
 - (1) Crosses the right-of-way of an unimproved public road, without a casing;
 - (2) Crosses without a casing, or makes a parallel encroachment on, the right-of-way of either a hard surfaced road, a highway, a public street, or a railroad;
 - (3) Is supported by a vehicular, pedestrian, railroad, or pipeline bridge; or
 - (4) Is used in a fabricated assembly, (including separators, mainline valve assemblies, cross- connections, and river crossing headers) or is used within five pipe diameters in any direction from the last fitting of a fabricated assembly, other than a transition piece or an elbow used in place of a pipe bend which is not associated with a fabricated assembly.
- (c) For Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in § 192.105 for uncased steel pipe that crosses the right-of-way of a hard surfaced road, a highway, a public street, or a railroad.
- (d) For Class 1 or Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in § 192.105 for each compressor station, regulator station, and measuring station.

§ 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 the steel pipe	(1) The plate, skelp, or coil used for the pipe must be micro-alloyed, fine grain, fully killed, continuously cast steel with calcium treatment.

(b) Fracture control	<p>(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.</p> <p>(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.</p> <p>(4) The pipe must be manufactured using API Spec 5L, product specification level 2 (incorporated by reference, see §192.7) for maximum operating pressures and minimum and maximum operating temperatures and other requirements under this section.</p> <p>(1) The toughness properties for pipe must address the potential for initiation, propagation and arrest of fractures in accordance with:</p> <p>(i) API Spec 5L (incorporated by reference, see §192.7); or</p> <p>(ii) American Society of Mechanical Engineers (ASME) B31.8 (incorporated by reference see §192.7); and</p> <p>(iii) Any correction factors needed to address pipe grades, pressures, temperatures, or gas compositions not expressly addressed in API Spec 5L, product specification level 2 or ASME B31.8 (incorporated by reference, see §192.7).</p> <p>(2) Fracture control must:</p> <p>(i) Ensure resistance to fracture initiation while addressing the full range of operating temperatures, pressures, gas compositions, pipe grade and operating stress levels, including maximum pressures and minimum temperatures for shut-in conditions, that the pipeline is expected to experience. If these parameters change during operation of the pipeline such that they are outside the bounds of what was considered in the design evaluation, the evaluation must be reviewed and updated to assure continued resistance to fracture initiation over the operating life of the pipeline.</p> <p>(ii) Address adjustments to toughness of pipe for each grade used and the decompression behavior of the gas at operating parameters;</p> <p>(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</p> <p>(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:</p>
----------------------	--

(c) Plate/coil quality control	<p>(A) The results of the Charpy impact test prescribed in SR5A must indicate at least 80 percent average shear for any single test on each heat of steel.</p> <p>(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.</p> <p>(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.</p> <p>(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.</p> <p>(2) A mill inspection program or internal quality management program must include (i) and either (i) or (iii) <u>include paragraph (c)(2)(i) of this section and either paragraph (c)(2)(ii) or (iii) of this section.</u></p> <p>(i) An ultrasonic test of the ends and at least 35 percent of the surface of the plate/coil or pipe to identify imperfections that impair serviceability such as laminations, cracks, and inclusions. At least 95 percent of the lengths of pipe manufactured must be tested. For all pipelines designed after December 22, 2008, the test must be done in accordance with ASTM A578/A578M Level B, or API Spec 5L Paragraph 7.8.10 (incorporated by reference, see §192.7) or equivalent method, and either</p> <p>(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</p> <p>(iii) A quality assurance monitoring program implemented by the operator that includes audits of:</p> <ul style="list-style-type: none"> (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

<p>(e) Mill hydrostatic test</p>	<p>(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:</p> <p>(i) A cross section of the weld seam of one pipe from each heat plus one pipe from each welding line per day; and</p> <p>(ii) For each sample cross section, a minimum of 13 readings (three for each heat affected zone, three in the weld metal, and two in each section of pipe base metal).</p> <p>(3) All of the seams must be ultrasonically tested after cold expansion and mill hydrostatic testing.</p> <p>(1) All pipe to be used in a new pipeline segment installed after October 1, 2015, must be hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 95 percent SMYS for 10 seconds.</p> <p>(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.</p> <p>(3) Pipe in operation on or after December 22, 2008, but before October 1, 2015, must have been 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 on internal test pressure and the allowance for end loading stresses imposed by the pipe mill hydrostatic testing equipment as allowed by “ANSI/API Spec 5L” (incorporated by reference, see §192.7).</p>
<p>(f) Coating</p>	<p>(1) The pipe must be protected against external corrosion by a non-shielding coating.</p> <p>(2) Coating on pipe used for trenchless installation must be non-shielding and resist abrasions and other damage possible during installation.</p> <p>(3) A quality assurance inspection and testing program for the coating must cover the surface quality of the bare pipe, surface cleanliness and chlorides, blast cleaning, application temperature control, adhesion, cathodic disbondment, moisture permeation, bending, coating thickness, holiday detection, and repair.</p>
<p>(g) Fittings and flanges</p>	<p>(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.</p> <p>(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.</p>

(h) Compressor stations	<p>(3) Valves, flanges and fittings must be rated based upon the required specification rating class for the alternative MAOP.</p> <p>(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.</p> <p>(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 conditioning 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.</p> <p>(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 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 in interstate agent agreement, or an intrastate pipeline is regulated by that State.</p>

§ 192.113 Longitudinal Joint Factor (E) for Steel Pipe

- (a) The longitudinal joint factor to be used in the design formula in § 192.105 is determined in accordance with the ~~following table~~ table 1 to this paragraph (a):

Longitudinal Specification	Pipe Class	Joint Factor
(E) ASTM A53/A53M	Seamless	1.00
	Electric resistance welded	1.00

	Furnace butt welded	0.60
ASTM A106/A106M (incorporated by reference, see § 192.7)	Seamless	1.00
ASTM A333/A333M (incorporated by reference see § 192.7)	Seamless	1.00
	Electric resistance welded	1.00
ASTM A381 (incorporated by reference see § 192.7)	Double submerged arc welded	1.00
ASTM A671 (incorporated by reference see § 192.7)	Electric fusion welded	1.00
ASTM A672 (incorporated by reference see § 192.7)	Electric fusion welded	1.00
ASTM A 691 (incorporated by reference see § 192.7)	Electric fusion welded	1.00
API Spec 5L (incorporated by reference see § 192.7)	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
	Furnace butt welded	0.60
Other	Pipe over 4 inches (102 millimeters)	0.80
Other	Pipe 4 inches (102 millimeters) or less	0.60

- (b) If the type of longitudinal joint cannot be determined, the joint factor to be used must not exceed that designated for "Other."

§ 192.115 Temperature Derating Factor (T) for Steel Pipe

The temperature derating factor to be used in the design formula in § 192.105 is determined as follows:

Gas Temperature in Degrees Fahrenheit (Celsius)	Temperature Derating Factor
250° F (121° C) or less	1.0
300° F (149° C)	0.967
350° F (177° C)	0.933
400° F (204° C)	0.900
450° F (232° C)	0.867

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

§ 192.117 [Removed and Reserved]

§ 192.119 [Removed and Reserved]

§ 192.121 Design of Plastic Pipe

- (a) *Design formula.* The design formulas for plastic pipe are determined in accordance with either of the following formulas:

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

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

P = Design pressure, gage, psi (kPa).

S = For thermoplastic pipe, the hydrostatic design basis (HDB) is determined in accordance with the listed specification at a temperature equal to 73°F (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-3/2012 (incorporated by reference, see § 192.7). For reinforced thermosetting plastic pipe, 11,000 psig (75,842 kPa).

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 (ANSI) preferred number series 10.

DF = Design Factor, a maximum of 0.32 unless otherwise specified for a particular material in this section.

- (b) General requirements for plastic pipe and components.
- (1) Except as provided in paragraphs (c) through (f) of this section, the design pressure for plastic pipe may not exceed a gauge pressure of 100 psig (689 kPa) for pipe used in:
 - (i) Distribution systems; or
 - (ii) Transmission lines in Class 3 and 4 locations.
 - (2) Plastic pipe may not be used where operating temperatures of the pipe will be:
 - (i) 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
 - (ii) Above the temperature at which the HDB used in the design formula under this section is determined.

- (3) Unless specified for a particular material in this section, the wall thickness of plastic pipe may not be less than 0.062 inches (1.57 millimeters).
 - (4) All plastic pipe must have a listed HDB in accordance with PPI TR 4/2012 (incorporated by reference, see §192.7).
- (c) Polyethylene (PE) pipe requirements.
- (1) For PE pipe produced after July 14, 2004, but before January 22, 2019, a design pressure of up to 125 psig may be used, provided:
 - (i) The material designation code is PE2406 or PE3408.
 - (ii) The pipe has a nominal size (Iron Pipe Size (IPS) or Copper Tubing Size (CTS)) of 12 inches or less (above nominal pipe size of 12 inches, the design pressure is limited to 100 psig); and
 - (iii) The wall thickness is not less than 0.062 inches (1.57 millimeters).
 - (2) For PE pipe produced on or after January 22, 2019, a DF of 0.40 may be used in the design formula, provided:
 - (i) The design pressure does not exceed 125 psig;
 - (ii) The material designation code is PE2708 or PE4710;
 - (iii) The pipe has a nominal size (IPS or CTS) of 24 inches or less; and
 - (iv) The wall thickness for a given outside diameter is not less than that listed in Table 1 to this paragraph (c)(2)(iv):

Table 1 to paragraph (c)(2)(iv):

PE Pipe - Minimum Wall Thickness and SDR Values		
Pipe Size (inches)	Minimum Wall Thickness (inches)	Corresponding SDR (values)
½" CTS	0.090	7.0
½" IPS	0.090	9.3
¾" CTS	0.090	9.7
¾" IPS	0.095	11
1" CTS	0.119 0.099	11
1" IPS	0.119	11
<u>1 ¼" CTS</u>	<u>0.121</u>	<u>11</u>
1 ¼" IPS	0.151	11
1 ½" IPS	0.173	11
2"	0.216	11
3"	0.259	13.5
4"	0.265	17.0
6"	0.315	21
8"	0.411	21
10"	0.512	21
12"	0.607	21
16"	0.762	21

18"	0.857	21
20"	0.952	21
22"	1.048	21
24"	1.143	21

(d) *Polyamide (PA-11) pipe requirements.*

- (1) For PA-11 pipe produced after January 23, 2009, but before January 22, 2019, a DF of 0.40 may be used in the design formula, provided:
 - (i) The design pressure does not exceed 200 psig;
 - (ii) The material designation code is PA32312 or PA32316;
 - (iii) The pipe has a nominal size (IPS or CTS) of 4 inches or less; and
 - (iv) The pipe has a standard dimension ratio of SDR - 11 or less (i.e., thicker wall pipe).
- (2) For PA- 11 pipe produced on or after January 22, 2019, a DF of 0.40 may be used in the design formula, provided:
 - (i) The design pressure does not exceed 250 psig;
 - (ii) The material designation code is PA32316;
 - (iii) The pipe has a nominal size (IPS or CTS) of 6 inches or less; and
 - (iv) The minimum wall thickness for a given outside diameter is not less than that listed in Table 2 to this paragraph (d)(2)(iv):

Table 2 to paragraph (d)(2)(iv):

PA-11 Pipe: Minimum Wall Thickness and SDR Values		
PA-11 Pipe: Minimum Wall Thickness and SDR Values		
<u>Pipe Size (inches)</u>	<u>Minimum Wall Thickness (inches)</u>	<u>Corresponding SDR (values)</u>
<u>1/2" CTS</u>	<u>0.090</u>	<u>7.0</u>
<u>1/2" IPS</u>	<u>0.090</u>	<u>9.3</u>
<u>3/4" CTS</u>	<u>0.090</u>	<u>9.7</u>
<u>3/4" IPS</u>	<u>0.095</u>	<u>11</u>
<u>1" CTS</u>	<u>0.119 0.099</u>	<u>11</u>
<u>1" IPS</u>	<u>0.119</u>	<u>11</u>
<u>1 1/4" CTS</u>	<u>0.121</u>	<u>11</u>
<u>1 1/4" IPS</u>	<u>0.151</u>	<u>11</u>
<u>1 1/2" IPS</u>	<u>0.173</u>	<u>11</u>
<u>2" IPS</u>	<u>0.216</u>	<u>11</u>
<u>3" IPS</u>	<u>0.259</u>	<u>13.5</u>

4" IPS	0.333	13.5
6" IPS	0.491	13.5
Pipe Size (inches)	Minimum Wall Thickness (inches)	Corresponding SDR (values)
½" CTS	0.090	7.0
½" IPS	0.090	9.3
¾" CTS	0.090	9.7
¾" IPS	0.095	11
1" CTS	0.119 0.099	11
1" IPS	0.119	11
1 ¼" CTS	0.124	11
1 ¼" IPS	0.151	11
1 ½" IPS	0.173	11
2" IPS	0.216	11
3" IPS	0.259	13.5
4" IPS	0.333	13.5
6" IPS	0.491	13.5

(e) *Polyamide (PA- 12) pipe requirements.* For PA- 12 pipe produced after January 22, 2019, a DF of 0.40 may be used in the design formula, provided:

- (1) The design pressure does not exceed 250 psig;
- (2) The material designation code is PA42316;
- (3) The pipe has a nominal size (IPS or CTS) of 6 inches or less; and
- (4) The minimum wall thickness for a given outside diameter is not less than that listed in Table 3 to [this](#) Paragraph (e)(4):

Table 3 to Paragraph (e)(4):

PA-12 Pipe: minimum wall thickness and SDR values		
Pipe Size (inches)	Minimum Wall Thickness (inches)	Corresponding dimension ratio SDR (values)
½" CTS	0.090	7.0
½" IPS	0.090	9.3
¾" CTS	0.090	9.7
¾" IPS	0.095	11
1" CTS	0.119 0.099	11
1" IPS	0.119	11
1 ¼" IPS	0.151	11
1 ½" IPS	0.173	11

2" IPS	0.216	11
3" IPS	0.259	13.5
4" IPS	0.333	13.5
6" IPS	<u>0.491</u>	<u>13.5</u>

(f) *Reinforced thermosetting plastic pipe requirements.*

- (1) Reinforced thermosetting plastic pipe may not be used at operating temperatures above 150 °F (66 °C).
- (2) 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 in 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)

§ 192.123 [Removed and Reserved]

§ 192.125 Design of Copper Pipe

- (a) Copper pipe used in mains must have a minimum wall thickness of 0.065 inches (1.65 millimeters) and must be hard drawn.
- (b) Copper pipe used in service lines must have wall thickness not less than that indicated in the following table:

Standard Size Inch (millimeter)	Nominal O.D. Inch (millimeter)	Wall Thickness, inch (millimeter)	
		Nominal	Tolerance
½ (13)	.625 (16)	.040 (1.06)	.0035 (.0889)
⅝ (16)	.750 (19)	.042 (1.07)	.0035 (.0889)
¾ (19)	.875 (22)	.045 (1.14)	.004 (.102)
1 (24)	1.125 (29)	.050 (1.27)	.004 (.102)
1 ¼ (32)	1.375 (35)	.055 (1.40)	.0045 (.1143)
1 ½ (38)	1.625 (41)	.060 (1.52)	.0045 (.1143)

- (c) Copper pipe used in mains and service line may not be used at pressures in excess of 100 p.s.i. (689 kPa) gage.
- (d) Copper pipe that does not have an internal corrosion resistant lining may not be used to carry gas that has an average hydrogen sulfide content of more than 0.3 grains/100 ft.³ (6.9/m³) under standard conditions. Standard conditions refers to 60°F and 14.7 p.s.i.a. (15.6°C and one atmosphere).

§ 192.127 Records: Pipe Design

- (a) For steel transmission pipelines installed after July 1, 2020], an operator must collect or make, and retain for the life of the pipeline, records documenting that the pipe is designed to withstand anticipated external pressures and loads in accordance with § 192.103 and documenting that the determination of design pressure for the pipe is made in accordance with § 192.105.
- (b) For steel transmission pipelines installed on or before July 1, 2020, if operators have records documenting pipe design and the determination of design pressure in accordance with §§ 192.103 and 192.105, operators must retain such records for the life of the pipeline.
- (c) For steel transmission pipeline segments installed on or before July 1, 2020, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of § 192.624 according to the terms of that section.

SUBPART D - DESIGN OF PIPELINE COMPONENTS

§ 192.141 Scope

This subpart prescribes minimum requirements for the design and installation of pipeline components and facilities. In addition, it prescribes requirements relating to protection against accidental over pressuring.

§ 192.143 General Requirements

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

§ 192.144 Qualifying Metallic Components

Notwithstanding any requirement of this subpart which incorporates by reference an edition of a document listed in § 192.7 or Appendix B of this part, a metallic component manufactured in accordance with any other edition of that document is qualified for use under this part if-

- (a) It can be shown through visual inspection of the cleaned component that no defect exists which might impair the strength or tightness of the component; and
- (b) The edition of the document under which the component was manufactured has equal or more stringent requirements for the following as an edition of that document currently or previously listed in § 192.7 or Appendix B of this part:

- (1) Pressure testing;
- (2) Materials; and
- (3) Pressure and temperature ratings.

§ 192.145 Valves

- (a) Except for cast iron and plastic valves, each valve must meet the minimum requirements of ANSI/API Spec 6D (incorporated by reference, see § 192.7), or to a national or international standard that provides an equivalent performance level. A valve may not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those requirements.
- (b) Each cast iron and plastic valve must comply with the following:
 - (1) The valve must have a maximum service pressure rating for temperatures that equal or exceed the maximum service temperature; and
 - (2) The valve must be tested as part of the manufacturing, as follows:
 - (i) With the valve in the fully open position, the shell must be tested with no leakage to a pressure at least 1.5 times the maximum service rating.
 - (ii) After the shell test, the seat must be tested to a pressure not less than 1.5 times the maximum service pressure rating. Except for swing check valves, test pressure during the seat test must be applied successively on each side of the closed valve with the opposite side open. No visible leakage is permitted.
 - (iii) After the last pressure test is completed, the valve must be operated through its full travel to demonstrate freedom from interference.
- (c) Each valve must be able to meet the anticipated operating conditions.
- (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.
- (f) Except for excess flow valves, plastic valves installed after January 22, 2019, must meet the minimum requirements of a listed specification. A valve may not be used under operating conditions that exceed the applicable pressure and temperature ratings contained in the listed specification.

§ 192.147 Flanges and Flange Accessories

- (a) Each flange or flange accessory (other than cast iron) must meet the minimum requirements of ASME/ANSI B16.5, ~~MSS SP-44~~ (incorporated by reference, see § 192.7),

~~or the equivalent.~~ ANSI/MSS SP-44 (incorporated by reference, see § 192.7), or the equivalent.

- (b) Each flange assembly must be able to withstand the maximum pressure at which the pipeline is to be operated and to maintain its physical and chemical properties at any temperature to which it is anticipated that it might be subjected in service.
- (c) Each flange on a flanged joint in cast iron pipe must conform in dimensions, drilling, face and gasket design to ASME/ANSI B16.1 (incorporated by reference, see § 192.7) and be cast integrally with the pipe, valve, or fitting.

§ 192.149 Standard Fittings

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

§ 192.150 Passage of Internal Inspection Devices

- (a) Except as provided in paragraphs (b) and (c) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must be designed and constructed to accommodate the passage of instrumented internal inspection devices in accordance with NACE SP0102, section 7 (incorporated by reference, see § 192.7).
- (b) This section does not apply to:
 - (1) Manifolds;
 - (2) Station piping such as at compressor stations, meter stations, or regulator stations;
 - (3) Piping associated with storage facilities, other than a continuous run of transmission line between a compressor station and storage facilities;
 - (4) Cross-overs;
 - (5) Sizes of pipe for which an instrumented internal inspection device is not commercially available;
 - (6) Transmission lines, operated in conjunction with a distribution system which are installed in Class 4 locations; ~~and~~
 - (7) Gathering lines; and
 - ~~(7)(8)~~ Other piping that, under § 190.9 of this chapter, the Administrator finds in a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices.
 - ~~(8)(1) Gathering lines; and~~
- (c) An operator encountering emergencies, construction time constraints or other unforeseen construction problems need not construct a new or replacement segment of a

transmission line to meet subparagraph (a) of this paragraph, if the operator determines and documents why impracticability prohibits compliance with subparagraph (a) of this paragraph. Within 30 days after discovering the emergency or construction problem the operator must petition, under § 190.9 of this chapter, for approval that design and construction to accommodate passage of instrumented internal inspection devices would be impracticable. If the petition is denied, within 1 year after the date of the notice of denial, the operator must modify that segment to allow passage of instrumented internal inspection devices.

§ 192.151 Tapping

- (a) Each mechanical fitting used to make a hot tap must be designed for at least the operating pressure of the pipeline.
- (b) Where a ductile iron pipe is tapped, the extent of full-thread engagement and the need for the use of outside-sealing service connections, tapping saddles, or other fixtures must be determined by service conditions.
- (c) Where a threaded tap is made in cast iron or ductile iron pipe, the diameter of the tapped hole may not be more than 25 percent of the nominal diameter of the pipe unless the pipe is reinforced, except that:
 - (1) Existing taps may be used for replacement service, if they are free of cracks and have good threads; and
 - (2) A 1 1/4 inch (32 millimeters) tap may be made in a 4 inch (102 millimeters) cast iron or ductile iron pipe, without reinforcement. However, in areas where climate, soil, and service conditions may create unusual external stresses on cast iron pipe, unreinforced taps may be used only on 6 inch (152 millimeters) or larger pipe.

§ 192.153 Components Fabricated by Welding

- (a) Except for branch connections and assemblies of standard pipe and fittings joined by circumferential welds, the design pressure of each component fabricated by welding, whose strength cannot be determined, must be established in accordance with paragraph UG-101 of the ASME Boiler and Pressure Vessel Code (BPVC) (Section VIII, Division 1) (incorporated by reference, see § 192.7).
- (b) Each prefabricated unit that uses plate and longitudinal seams must be designed, constructed, and tested in accordance with section 1 of the ASME BPVC (*Rules for Construction of Pressure Vessels* as defined in either Section VIII, Division 1 or Section VIII, Division 2; incorporated by reference, see §192.7), except for the following:
 - (1) Regularly manufactured butt-welding fittings.
 - (2) Pipe that has been produced and tested under a specification listed in Appendix B to this part.
 - (3) Partial assemblies such as split rings or collars.
 - (4) Prefabricated units that the manufacturer certifies have been tested to at least twice the maximum pressure to which they will be subjected under the anticipated operating conditions.
- (c) Orange-peel bull plugs and orange-peel swages may not be used on pipelines that are to operate at a hoop stress of 20 percent or more of the SMYS of the pipe.

- (d) Except for flat closures designed in accordance with the ASME BPVC, (Section VIII, Division 1 or Division 2), (both incorporated by reference, see § 192.7) flat closures and fish tails may not be used on pipe that either operates at 100 p.s.i. (689 kPa kilopascals) gage, or more, or that is more than 3 inches (76 millimeters) nominal diameter.
- (e) The test requirements for a prefabricate unit or pressure vessel, defined for this paragraph as components with a design pressure established in accordance with paragraph (a) or paragraph (b) of this section are as follows.
 - (1) A prefabricated unit or pressure vessel installed after July 14, 2004 is not subject to the strength testing requirements at §192.505(b) provided the component has been tested in accordance with paragraph (a) or paragraph (b) of this section and with a test factor of at least 1.3 times MAOP.
 - (2) A prefabricated unit or pressure vessel must be tested for a duration specified as follows.
 - (i) A prefabricated unit or pressure vessel installed after July 14, 2004, but before October 1, 2021 is exempt from §§ 192.505(c) and (d) and 192.507(c) provided it has been tested for a duration consistent with the ASME BPVC requirements referenced in paragraph (a) or (b) of this section.
 - (ii) A prefabricated unit or pressure vessel installed on or after October 1, 2021 must be tested for the duration specified in either § 192.505(c) or (d), § 192.507(c), or § 192.509(a), whichever is applicable for the pipeline in which the component is being installed.
 - (3) For any prefabricated unit or pressure vessel permanently or temporarily installed on a pipeline facility, an operator must either:
 - (i) Test the prefabricated unit or pressure vessel in accordance with this section and Subpart J of this part after it has been placed on its support structure at its final installation location. The test may be performed before or after it has been tied-in to the pipeline. Test records that meet § 192.517(a) must be kept for the operational life of the prefabricated unit or pressure vessel; or
 - (ii) For a prefabricated unit or pressure vessel that is pressure tested prior to installation or where a manufacturer's pressure test is used in accordance with paragraph (e) of this section, inspect the prefabricated unit or pressure vessel after it has been placed on its support structure at its final installation location and confirm that the prefabricated unit or pressure vessel was not damaged during any prior operation, transportation, or installation into the pipeline. The inspection procedure and documented inspection must include visual inspection for vessel damage, including, at a minimum, inlets, outlets, and lifting locations. Injurious defects that are an integrity threat may include dents, gouges, bending, corrosion, and cracking. This inspection must be performed prior to operation but may be performed either before or after it has been tied-in to the pipeline. If injurious defects that are an integrity threat are found, the prefabricated unit or pressure vessel must be either non-destructively tested, re-pressure tested, or remediated in accordance with applicable part 192 requirements for a fabricated unit or with the applicable ASME BPVC requirements referenced in paragraphs (a) or (b) of this section. Test, inspection, and repair records for the

fabricated unit or pressure vessel must be kept for the operational life of the component. Test records must meet the requirements in §192.517(a).

- (4) An initial pressure test from the prefabricated unit or pressure vessel manufacturer may be used to meet the requirements of this section with the following conditions:
 - (i) The prefabricated unit or pressure vessel is newly-manufactured and installed on or after October 1, 2021, except as provided in paragraph (e)(4)(ii) of this section.
 - (ii) An initial pressure test from the fabricated unit or pressure vessel manufacturer or other prior test of a new or existing prefabricated unit or pressure vessel may be used for a component that is temporarily installed in a pipeline facility in order to complete a testing, integrity assessment, repair, odorization, or emergency response-related task, including noise or pollution abatement. The temporary component must be promptly removed after that task is completed. If operational and environmental constraints require leaving a temporary prefabricated unit or pressure vessel under this paragraph in place for longer than 30 days, the operator must notify PHMSA and State or local pipeline safety authorities, as applicable, in accordance with §192.18.
 - (iii) The manufacturer's pressure test must meet the minimum requirements of this part; and
 - (iv) The operator inspects and remediates the prefabricated unit or pressure vessel after installation in accordance with paragraph (e)(3)(ii) of this section.
- (5) An existing prefabricated unit or pressure vessel that is temporarily removed from a pipeline facility to complete a testing, integrity assessment, repair, odorization, or emergency response-related task, including noise or pollution abatement, and then re-installed at the same location must be inspected in accordance with paragraph (e)(3)(ii) of this section; however, a new pressure test is not required provided no damage or threats to the operational integrity of the prefabricated unit or pressure vessel were identified during the inspection and the MAOP of the pipeline is not increased.
- (6) Except as provided in paragraphs (e)(4)(ii) and (5) of this section, on or after October 1, 2021, an existing prefabricated unit or pressure vessel relocated and operated at a different location must meet the requirements of this part and the following:
 - (i) The prefabricated unit or pressure vessel must be designed and constructed in accordance with the requirements of this part at the time the vessel is returned to operational service at the new location; and
 - (ii) The prefabricated unit or pressure vessel must be pressure tested by the operator in accordance with the testing and inspection requirements of this part applicable to newly installed prefabricated units and pressure vessels.

§ 192.155 Welded Branch Connections

Each welded branch connection made to pipe in the form of a single connection, or in a header or manifold as a series of connections, must be designed to ensure that the strength of the pipeline system is not reduced, taking into account the stresses in the remaining pipe wall due to the opening in

the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening and any external loadings due to thermal movement, weight, and vibration.

§ 192.157 Extruded Outlets

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

§ 192.159 Flexibility

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

§ 192.161 Supports and Anchors

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

§ 192.163 Compressor Stations: Design and Construction

- (a) *Location of compressor building.* Each main compressor building of a compressor station

must be located on property under the control of the operator. It must be far enough away from adjacent property, not under control of the operator, to minimize the possibility of fire being communicated to the compressor building from structures on adjacent property. There must be enough open space around the main compressor building to allow the free movement of fire-fighting equipment.

- (b) *Building construction.* Each building on a compressor station site must be made of noncombustible materials if it contains either:
 - (1) Pipe more than 2 inches (51 millimeters) in diameter that is carrying gas under pressure; or
 - (2) Gas handling equipment other than gas utilization equipment used for domestic purposes.
- (c) *Exits.* Each operating floor of a main compressor building must have at least two separated and unobstructed exits located so as to provide a convenient possibility of escape and an unobstructed passage to a place of safety. Each door latch on an exit must be of a type which can be readily opened from the inside without a key. Each swinging door located in an exterior wall must be mounted to swing outward.
- (d) *Fenced areas.* Each fence around a compressor station must have at least two gates located so as to provide a convenient opportunity for escape to a place of safety or have other facilities affording a similarly convenient exit from the area. Each gate located within 200 feet (61 meters) of any compressor plant building must open outward and, when occupied, must be openable from the inside without a key.
- (e) *Electrical facilities.* Electrical equipment and wiring installed in compressor stations must conform to the NFPA-70 [\(incorporated by reference, see § 192.7\)](#), so far as that code is applicable.

§ 192.165 Compressor Stations: Liquid Removal

- (a) Where entrained vapors in gas may liquefy under the anticipated pressure and temperature conditions, the compressor must be protected against the introduction of those liquids in quantities that could cause damage.
- (b) Each liquid separator used to remove entrained liquids at a compressor station must:
 - (1) Have a manually operable means of removing these liquids;
 - (2) Where slugs of liquid could be carried into the compressors, have either automatic liquid removal facilities, an automatic compressor shut-down device, or a high liquid level alarm; and
 - (3) Be manufactured in accordance with Section VIII ASME Boiler and Pressure Vessel Code (BPVC) (incorporated by reference, see § 192.7) and the additional requirements of § 192.153(e), except that liquid separators constructed of pipe and fittings without internal welding must be fabricated with a design factor of 0.4 or less.

§ 192.167 Compressor Station: Emergency ShutDown

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

- (1) It must be able to block gas out of the station and blow down the station piping.
 - (2) It must discharge gas from the blowdown piping at a location where the gas will not create a hazard.
 - (3) It must provide means for the shutdown of gas compressing equipment, gas fires, and electrical facilities in the vicinity of gas headers and in the compressor building except, that:
 - (i) Electrical circuits that supply emergency lighting required to assist station personnel in evacuating the compressor building and the area in the vicinity of the gas headers must remain energized; and
 - (ii) Electrical circuits needed to protect equipment from damage may remain energized.
 - (4) It must be operable from at least two locations, each of which is:
 - (i) Outside the gas area of the station;
 - (ii) Near the exit gates, if the station is fenced, or near emergency exits, if not fenced; and
 - (iii) Not more than 500 feet (153 meters) from the limits of the station.
- (b) If a compressor station supplies gas directly to a distribution system with no other adequate source of gas available, the emergency shutdown system must be designed so that it will not function at the wrong time and cause the unintended outage on the distribution system.

§ 192.169 Compressor Stations: Pressure Limiting Devices

- (a) Each compressor station must have pressure relief or other suitable protective devices of sufficient capacity and sensitivity to ensure that the maximum allowable operating pressure of the station piping and equipment is not exceeded by more than 10 percent.
- (b) Each vent line that exhausts gas from the pressure relief valves of a compressor station must extend to a location where the gas may be discharged without hazard.

§ 192.171 Compressor Stations: Additional Safety Equipment

- (a) Each compressor station must have adequate fire protection facilities. If fire pumps are a part of these facilities, their operation may not be affected by the emergency shutdown system.
- (b) Each compressor station prime mover, other than an electrical induction or synchronous motor, must have an automatic device to shut down the unit before the speed of either the prime mover or the driven unit exceeds a maximum safe speed.
- (c) Each compressor unit in a compressor station must have a shutdown or alarm device that operates in the event of inadequate cooling or lubrication of the unit.
- (d) Each compressor station gas engine that operates with pressure gas injection must be equipped so that the stoppage of the engine automatically shuts off the fuel and vents the engine distribution manifold.
- (e) Each muffler for a gas engine in a compressor station must have vent slots or holes in baffles of each compartment to prevent gas from being trapped in the muffler.

§ 192.173 Compressor Stations: Ventilation

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

§ 192.175 Pipe-Type and Bottle-Type Holders

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

$$C = (3D \times P \times F)/1000 \text{ in inches; } (C = (3D \times P \times F)/6,895 \text{ in millimeters}$$

In which:

C = Minimum clearance between pipe containers or bottles in inches (millimeters).

D = Outside diameter of pipe containers or bottles in inches (millimeters) P = Maximum allowable operating pressure, psi (kPa) gauge.

F = Design factor as set forth in § 192.111 of this part.

§ 192.177 Additional Provisions for Bottle-Type Holders

- (a) Each bottle-type holder must be:
 - (1) Located on a site entirely surrounded by fencing that prevents access by unauthorized persons and with minimum clearance from the fence as follows:

Maximum Allowable Operating Pressure	Minimum Clearance Feet (meters)
Less than 1,000 p.s.i. (7 MPa) gage	25 (7.6)
1,000 p.s.i. (7 MPa) or more	100 (31)

- (2) Designed using the design factors set forth in § 192.111; and
 - (3) Buried with a minimum cover in accordance with § 192.327.
- (b) Each bottle-type holder manufactured from steel that is not weldable under field conditions must comply with the following:
 - (1) A bottle-type holder made from alloy steel must meet the chemical and tensile requirements for the various grades of steel in ASTM A372/A372M (incorporated by reference, see § 192.7).
 - (2) The actual yield-tensile ratio of the steel may not exceed 0.85.
 - (3) Welding may not be performed on the holder after it has been heat treated or stress relieved, except that copper wires may be attached to the small diameter

portion of the bottle end closure for cathodic protection if a localized thermite welding process is used.

- (4) The holder must be given a mill hydrostatic test at a pressure that produces a hoop stress at least equal to 85 percent of the SMYS.
- (5) The holder, connection pipe, and components must be leak tested after installation as required by Subpart J of this part.

§ 192.179 Transmission Line Valves

- (a) Each transmission line must have sectionalizing block valves spaced as follows, unless in a particular case the Administrator finds that alternative spacing would provide an equivalent level of safety:
 - (1) Each point on the pipeline in a Class 4 location must be within 2 1/2 miles (4 kilometers) of a valve.
 - (2) Each point on the pipeline in a Class 3 location must be within 4 miles (6.4 kilometers) of a valve.
 - (3) Each point on the pipeline in a Class 2 location must be within 7 1/2 miles (12 kilometers) of a valve.
 - (4) Each point on the pipeline in a Class 1 location must be within 10 miles (16 kilometers) of a valve.
- (b) Each sectionalizing block valve on a transmission line must comply with the following:
 - (1) The valve and the operating device to open or close the valve must be readily accessible and protected from tampering and damage.
 - (2) The valve must be supported to prevent settling of the valve or movement of the pipe to which it is attached.
- (c) Each section of transmission line between main line valves must have a blowdown valve with enough capacity to allow the transmission line to be blown down as rapidly as practicable. Each blowdown discharge must be located so the gas can be blown to the atmosphere without hazard and, if the transmission line is adjacent to an overhead electric line, so that the gas is directed away from the electrical conductors.
- (d) Offshore segments of transmission lines must be equipped with valves or other components to shut off the flow of gas to an offshore platform in an emergency.
- (e) For onshore transmission pipeline segments with diameters greater than or equal to 6 inches that are constructed after April 10, 2023, the operator must install rupture-mitigation valves (RMV) or an alternative equivalent technology whenever a valve must be installed to meet the appropriate valve spacing requirements of this section. An operator seeking to use alternative equivalent technology must notify PHMSA in accordance with the procedures set forth in paragraph (g) of this section. All RMVs and alternative equivalent technologies installed pursuant to this paragraph (e) must meet the requirements of § 192.636. The installation requirements in this paragraph (e) do not apply to pipe segments with a potential impact radius (PIR), as defined in § 192.903, that is less than or equal to 150 feet in either Class 1 or Class 2 locations. An operator may request an extension of the installation compliance deadline requirements of this paragraph (e) if it can demonstrate to PHMSA, in accordance with the notification procedures in § 192.18, that

those installation compliance deadlines would be economically, technically, or operationally infeasible for a particular new pipeline.

- (f) For entirely replaced onshore transmission pipeline segments, as defined in § 192.3, with diameters greater than or equal to 6 inches and that are installed after April 10, 2023, the operator must install RMVs or an alternative equivalent technology whenever a valve must be installed to meet the appropriate valve spacing requirements of this section. An operator seeking to use alternative equivalent technology must notify PHMSA in accordance with the procedures set forth in paragraph (g) of this section. All RMVs and alternative equivalent technologies installed pursuant to this paragraph (f) must meet the requirements of § 192.636. The requirements of this paragraph (f) apply when the applicable pipeline replacement project involves a valve, either through addition, replacement, or removal. The installation requirements in this paragraph (f) do not apply to pipe segments with a PIR, as defined in § 192.903, that is less than or equal to 150 feet in either Class 1 or Class 2 locations. An operator may request an extension of the installation compliance deadline requirements of this paragraph (f) if it can demonstrate to PHMSA, in accordance with the notification procedures in § 192.18, that those installation compliance deadlines would be economically, technically, or operationally infeasible for a particular pipeline replacement project.
- (g) If an operator elects to use alternative equivalent technology in accordance with paragraph (e) or (f) of this section, the operator must notify PHMSA in accordance with the procedures in § 192.18. The operator must include a technical and safety evaluation in its notice to PHMSA. Valves that are installed as alternative equivalent technology must comply with §§ 192.634 and 192.636. An operator requesting use of manual valves as an alternative equivalent technology must also include within the notification submitted to PHMSA a demonstration that installation of an RMV as otherwise required would be economically, technically, or operationally infeasible. An operator may use a manual compressor station valve at a continuously manned station as an alternative equivalent technology, and use of such valve would not require a notification to PHMSA in accordance with § 192.18, but it must comply with § 192.636.
- (h) The valve spacing requirements of paragraph (a) of this section do not apply to pipe replacements on a pipeline if the distance between each point on the pipeline and the nearest valve does not exceed:
- (1) Four (4) miles in Class 4 locations, with a total spacing between valves no greater than 8 miles;
 - (2) Seven-and-a-half (7 1/2) miles in Class 3 locations, with a total spacing between valves no greater than 15 miles; or
 - (3) Ten (10) miles in Class 1 or 2 locations, with a total spacing between valves no greater than 20 miles.

§ 192.181 Distribution Line Valves

- (a) Each high-pressure distribution system must have valves spaced so as to reduce the time to shut down a section of main in an emergency. The valve spacing is determined by

the operating pressure, the size of the mains, and the local physical conditions.

- (b) Each regulator station controlling the flow or pressure of gas in a distribution system must have a valve installed on the inlet piping at a distance from the regulator station sufficient to permit the operation of the valve during an emergency that might preclude access to the station.
- (c) Each valve on a main installed for operating or emergency purposes must comply with the following:
 - (1) The valve must be placed in a readily accessible location so as to facilitate its operation in an emergency.
 - (2) The operating stem or mechanism must be readily accessible.
 - (3) If the valve is installed in a buried box or enclosure, the box or enclosure must be installed so as to avoid transmitting external loads to the main.

§ 192.183 Vaults: Structural Design Requirements

- (a) Each underground vault or pit for valves, pressure relieving, pressure limiting, or pressure regulating stations, must be able to meet the loads which may be imposed upon it, and to protect installed equipment.
- (b) There must be enough working space so that all of the equipment required in the vault or pit can be properly installed, operated, and maintained.
- (c) Each pipe entering, or within, a regulator vault or pit must be steel for sizes 10 inches (254 millimeters), and less, except that control and gauge piping may be copper. Where pipe extends through the vault or pit structure, provision must be made to prevent the passage of gasses or liquids through the opening and to avert strains in the pipe.

§ 192.185 Vaults: Accessibility

Each vault must be located in an accessible location and, so far as practical, away from:

- (a) Street intersections or points where traffic is heavy or dense;
- (b) Points of minimum elevation, catch basins, or places where the access cover will be in the course of surface waters; and
- (c) Water, electric, steam, or other facilities.

§ 192.187 Vaults: Sealing, Venting, and Ventilation

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

- (a) When the internal volume exceeds 200 cubic feet (5.7 cubic meters):
 - (1) The vault or pit must be ventilated with two ducts, each having at least the ventilating effect of a pipe 4 inches (102 millimeters) in diameter;
 - (2) The ventilation must be enough to minimize the formation of combustible atmosphere in the vault or pit; and
 - (3) The ducts must be high enough above grade to disperse any gas-air mixtures that might be discharged.
- (b) When the internal volume is more than 75 cubic feet (2.1 cubic meters) but less than 200 cubic feet (5.7 cubic meters):

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

§ 192.189 Vaults: Drainage and Waterproofing

- (a) Each vault must be designed so as to minimize the entrance of water.
- (b) A vault containing gas piping may not be connected by means of a drain connection to any other underground structure.
- (c) Electrical equipment in vaults must conform to the applicable requirements of Class 1, Group D, of the National Electrical Code, NFPA-70 (incorporated by reference see § 192.7).

§ 192.191 [Removed and Reserved]

§ 192.193 Valve Installation in Plastic Pipe

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

§ 192.195 Protection Against Accidental Overpressuring

- (a) *General requirements.* Except as provided in § 192.197, each pipeline that is connected to a gas source so that the maximum allowable operating pressure could be exceeded as the result of pressure control failure or of some other type of failure, must have pressure relieving or pressure limiting devices that meet the requirements of §§ 192.199 and 192.201.
- (b) *Additional requirements for distribution systems.* Each distribution system that is supplied from a source of gas that is at a higher pressure than the maximum allowable operating pressure for the system must:
 - (1) Have pressure regulation devices capable of meeting the pressure, load, and other service conditions that will be experienced in normal operation of the system, and that could be activated in the event of failure of some portion of the system; and
 - (2) Be designed so as to prevent accidental overpressuring.

§ 192.197 Control of Pressure of Gas Delivered from High-Pressure Distribution Systems

- (a) Each operator shall establish a maximum actual operating pressure for each distribution system as required by § 192.622.
- (b) If the maximum actual operating pressure of the distribution system is 60 p.s.i. (414 kPa) gage, or less, and a service regulator having the following characteristics is used, no other pressure limiting device is required:

- (1) A regulator capable of reducing line pressure to pressures required to safely operate the customers' gas utilization equipment.
 - (2) A regulator with an internal relief valve vented to the outside atmosphere or an overpressure control device.
A single port valve with the orifice size commensurate with the inlet pressure to assure adequate volume and pressure to the customer and also assures the overpressure control device prevents the build-up of pressure that would cause the unsafe operation of the customers' gas utilization equipment.
 - (3) A valve seat made of resilient material designed to withstand abrasion of the gas, impurities in gas, cutting of the valve, and to resist permanent deformation when pressed against the valve port.
 - (4) Pipe connections to the regulator not exceeding 2 inches (51 millimeters) in diameter.
 - (5) A regulator that, under normal operating conditions, will regulate the downstream pressure within the necessary limits of accuracy and prevents the build-up of pressure under no flow conditions that would cause the unsafe operation of the customers' gas utilization equipment.
 - (6) A self-contained regulator with no external static or control lines.
- (c) If the maximum actual operating pressure of the distribution system is 60 p.s.i. (414 kPa) gage, or less, and a regulator that does not have all the characteristics listed in paragraph (b) of this section is used, or if the gas contains materials that seriously affects the operation of the regulator, there must be suitable protective devices installed to prevent over-pressuring the customers' gas utilization equipment if the regulator fails.
- (d) If the maximum actual operating pressure of the distribution system exceeds 60 p.s.i. (414 kPa) gage, one of the following methods must be used to regulate and limit to a safe value, the pressure delivered to the customers' gas utilization equipment:
- (1) A service regulator having the characteristics listed in paragraph (b) this part, and another regulator located upstream from the service regulator. The upstream regulator may not be set to maintain a pressure higher than 60 p.s.i. (414 kPa) gage. If the upstream regulator does not have an internal relief valve of sufficient capacity to limit the pressure to the service regulator to 60 p.s.i.(414 kPa) gage, a device must be installed between the upstream regulator and service regulator to limit the pressure to the service regulator to 60 p.s.i.(414 kPa) gage or less in case the upstream regulator fails to function properly. This device may be either a regulator, relief valve, or an automatic shutoff that shuts if the pressure on the inlet of the service regulator exceeds 60 p.s.i. (414 kPa) gage, and remains closed until manually reset.
 - (2) A service regulator and a monitoring regulator set to limit, to a safe value, the pressure delivered to the customer. Both regulators must be constructed to withstand the maximum inlet pressure.
 - (3) A service regulator and an automatic shutoff device that closes upon an unsafe rise in pressure downstream from the regulator and remains closed until manually reset.
- (e) If the maximum actual operating pressure does not exceed 125 p.s.i. (862 kPa) gage, a service regulator having the characteristics listed in paragraph (b) of this section and a

manufacturer's inlet working pressure rating of 125 p.s.i. (862 kPa) gage or higher, may be used. If the internal relief valve capacity will prevent the downstream pressure from exceeding a safe value, or an overpressure control device is installed, no additional pressure limiting device is required.

§ 192.199 Requirements for Design of Pressure Relief and Limiting Devices

Except for rupture discs, each pressure relief or pressure limiting device must:

- (a) Be constructed of materials such that the operation of the device will not be impaired by corrosion;
- (b) Have valves and valve seats that are designed not to stick in a position that will make the device inoperative;
- (c) Be designed and installed so that it can be readily operated to determine if the valve is free, can be tested to determine the pressure at which it will operate, and can be tested for leakage when in the closed position;
- (d) Have support made of noncombustible material;
- (e) Have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without undue hazard;
- (f) Be designed and installed so that the size of the openings, pipe, and fittings located between the system to be protected and the pressure relieving device, and the size of the vent line, are adequate to prevent hammering of the valve and to prevent impairment of relief capacity;
- (g) Where installed at a district regulator station to protect a pipeline system from overpressuring, be designed and installed to prevent any single incident such as an explosion in a vault or damage by a vehicle from affecting the operation of both the overpressure protective device and the district regulator; and
- (h) Except for a valve that will isolate the system under protection from its source of pressure, be designed to prevent unauthorized operation of any stop valve that will make the pressure relief valve or pressure limiting device inoperative.
- (i) Each regulator station must be provided with reasonable protection from physical damage due to vehicles or other causes by being placed in a suitable location or by installation of barricades.

§ 192.201 Required Capacity of Pressure Relieving and Limiting Stations

- (a) Each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline must have enough capacity, and must be set to operate, to insure the following:
 - (1) In a low-pressure distribution system, the pressure may not cause the unsafe operation of any connected and properly adjusted gas utilization equipment.
 - (2) In pipelines other than a low-pressure distribution system:
 - (i) If the maximum allowable operating pressure is 60 p.s.i. (414 kPa) or more, the pressure may not exceed the maximum allowable operating pressure

plus 10 percent, or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower;

- (ii) If the maximum allowable operating pressure is 12 p.s.i. (83 kPa) gage or more, but less than 60 p.s.i. (414 kPa) gage, the pressure may not exceed the maximum allowable operating pressure plus 6 p.s.i. (41kPa) gage; or
 - (iii) If the maximum allowable operating pressure is less than 12 p.s.i. (83 kPa) gage, the pressure may not exceed the maximum allowable operating pressure plus 50 percent.
- (b) When more than one pressure regulating or compressor station feeds into a pipeline, relief valves or other protective devices must be installed at each station to ensure that the complete failure of the largest capacity regulator or compressor, or any single run of lesser capacity regulators or compressors in that station, will not impose pressures on any part of the pipeline or distribution system in excess of those for which it was designed, or against which it was protected, whichever is lower.
 - (c) Relief valves or other pressure limiting devices must be installed at or near each regulator station in a low-pressure distribution system, with a capacity to limit the maximum pressure in the main to a pressure that will not exceed the safe operating pressure for any connected and properly adjusted gas utilization equipment.

§ 192.203 Instrument, Control, and Sampling Pipe and Components

- (a) Applicability. This section applies to the design of instrument, control and sampling pipe and components. It does not apply to permanently closed systems, such as fluid-filled temperature responsive devices.
- (b) Materials and design. All materials employed for pipe and components must be designed to meet the particular conditions of service and the following:
 - (1) Each takeoff connection and attaching boss, fitting, or adapter must be made of suitable material, be able to withstand the maximum service pressure and temperature of the pipe or equipment to which it is attached, and be designed to satisfactorily withstand all stresses without failure by fatigue.
 - (2) Except for takeoff lines that can be isolated from sources of pressure by other valving, a shutoff valve must be installed in each take offline as near as practicable to the point of take-off. Blowdown valves must be installed where necessary.
 - (3) Brass or copper material may not be used for metal temperatures greater than 400°F (204°C).
 - (4) Pipe or components that may contain liquids must be protected by heating or other means from damage due to freezing.
 - (5) Pipe or components in which liquids may accumulate must have drains or drips.
 - (6) Pipe or components subject to clogging from solids or deposits must have suitable connections for cleaning.
 - (7) The arrangement of pipe, components, and supports must provide safety under anticipated operating stresses.
 - (8) Each joint between sections of pipe, and between pipe and valves or fittings, must be made in a manner suitable for the anticipated pressure and temperature condition. Slip type expansion joints may not be used. Expansion must be allowed for by providing flexibility within the system itself.

- (9) Each control line must be protected from anticipated causes of damage and must be designed and installed to prevent damage to any one control line from making both the regulator and the over-pressure protective device inoperative.

§ 192.204 Risers Installed After January 22, 2019

- (a) Riser designs must be tested to ensure safe performance under anticipated external and internal loads acting on the assembly.
- (b) Factory assembled anodeless risers must be designed and tested in accordance with ASTM F1973-13 (incorporated by reference, see §192.7).
- (c) All risers used to connect regulator stations to plastic mains must be rigid and designed to provide adequate support and resist lateral movement. Anodeless risers used in accordance with this paragraph must have a rigid riser casing.

§ 192.205 Records: Pipeline Components

- (a) For steel transmission pipelines installed after July 1, 2020, an operator must collect or make, and retain for the life of the pipeline, records documenting the manufacturing standard and pressure rating to which each valve was manufactured and tested in accordance with this subpart. Flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi (X42) or greater and with nominal diameters of greater than 2 inches must have records documenting the manufacturing specification in effect at the time of manufacture, including yield strength, ultimate tensile strength, and chemical composition of materials.
- (b) For steel transmission pipelines installed on or before July 1, 2020, if operators have records documenting the manufacturing standard and pressure rating for valves, flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi (X42) or greater and with nominal diameters of greater than 2 inches, operators must retain such records for the life of the pipeline.
- (c) For steel transmission pipeline segments installed on or before July 1, 2020, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of § 192.624 according to the terms of that section.

SUBPART E - WELDING OF STEEL IN PIPELINES

§ 192.221 Scope

- (a) This subpart prescribes minimum requirements for welding steel materials in pipelines.
- (b) This subpart does not apply to welding that occurs during the manufacture of steel pipe or steel pipeline components.

§ 192.225 Welding - Procedures

- (a) Welding must be performed by a qualified welder or welding operator in accordance with welding procedures qualified under section 5 ([except for Note 2 in section 5.4.2.2](#)), section 12, Appendix A or Appendix B of API Std 1104 (incorporated by reference, see § 192.7), or Section IX of the ASME Boiler and Pressure Vessel Code (ASME BPVC) (incorporated by reference, see § 192.7) to produce welds meeting the requirements of this subpart. The quality of the test welds used to qualify welding procedures must be determined by

destructive testing in accordance with the applicable welding standard(s).

- (b) Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.

§ 192.227 Qualification of Welders and Welding Operators

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

§ 192.229 Limitations on Welders and Welding Operators

- (a) No welder or welding operator whose qualification is based on nondestructive testing may weld compressor station pipe and components.
- (b) A welder or welding operator may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder or welding operator was engaged in welding with that process. Alternatively, welders or welding operators may demonstrate they have engaged in a specific welding process if they have performed a weld with that process if they have performed a weld with that process that was tested and found acceptable under section 6, 9, 12, or Appendix A of API Std 1104 (incorporated by reference, see § 192.7) within the preceding 7½ months.
- (c) A welder or welding operator qualified under § 192.227(a):
 - (1) May not weld on pipe to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS unless within the preceding 6 calendar months the welder or welding operator has had one weld tested and found acceptable under either section 6, section 9, section 12 or Appendix A of API Std 1104 (incorporated by reference, see § 192.7). Alternatively, welders or welding operators may maintain an ongoing qualification status by performing welds tested and found acceptable under the above acceptance criteria at least twice each calendar year, but at intervals not exceeding 7 ½ months. A welder or welding operator qualified under an earlier edition of a standard listed in § 192.7 of this part may weld but may not re-qualify under that earlier edition; and
 - (2) May not weld on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS unless the welder or welding operator is tested in accordance with paragraph (c)(1) of this section or requalifies under paragraph (d)(1) or (d)(2) of this section.
- (d) A welder or welding operator qualified under § 192.227(b) may not weld unless:

- (1) Within the preceding 15 calendar months, but at least once each calendar year, the welder or welding operator has re-qualified under § 192.227(b); or
- (2) Within the preceding 7 1/2 calendar months, but at least twice each calendar year, the welder or welding operator has had -
 - i. A production weld cut out, tested, and found acceptable in accordance with the qualifying test; or
 - ii. For a welder who works only on service lines 2 inches (51 millimeters) or smaller in diameter, the welder has had two sample welds tested and found acceptable in accordance with the test in section III of Appendix C of this part.

§ 192.231 Protection from Weather

The welding operation must be protected from weather conditions that would impair the quality of the completed weld.

§ 192.233 Miter Joints

- (a) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent or more of SMYS may not deflect the pipe more than 3°.
- (b) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of less than 30 percent, but more than 10 percent, of SMYS may not deflect the pipe more than 12 1/2° and must be a distance equal to one pipe diameter or more away from any other miter joint, as measured from the crotch of each joint.
- (c) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 10 percent or less of SMYS may not deflect the pipe more than 90°.

§ 192.235 Preparation for Welding

Before beginning any welding, the welding surfaces must be clean and free of any material that may be detrimental to the weld, and the pipe or component must be aligned to provide the most favorable condition for depositing the root bead. This alignment must be preserved while the root bead is being deposited.

§ 192.241 Inspection and Test of Welds

- (a) Visual inspection of welding must be conducted by an individual qualified by appropriate training and experience to ensure that:
 - (1) The welding is performed in accordance with the welding procedure, and
 - (2) The weld is acceptable under paragraph (c) of this section.
- (b) The welds on a pipeline to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS must be nondestructively tested in accordance with § 192.243, except that welds that are visually inspected and approved by a qualified welding inspector need not be nondestructively tested if:
 - (1) The pipe has a nominal diameter of less than 6 inches (152 millimeters); or
 - (2) The pipeline is to be operated at a pressure that produces a hoop stress of less than 40 percent of SMYS and the welds are so limited in number that nondestructive testing is impractical.

- (c) The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in Section 9 or Appendix A of API Std 1104 (incorporated by reference, see § 192.7). Appendix A of API Std 1104 may not be used to accept cracks.
- (d) Each operator must designate in writing a welding inspector to perform visual inspections of welds under this paragraph.

§ 192.243 Nondestructive Testing

- (a) Nondestructive testing of welds must be performed by any process, other than trepanning, that will clearly indicate defects that may affect the integrity of the weld.
- (b) Nondestructive testing of welds must be performed:
 - (1) In accordance with written procedures; and
 - (2) By persons who have been trained and qualified in accordance with the requirements of API Standard 1104. These persons must also be qualified on the equipment employed in the nondestructive testing.
- (c) Procedures must be established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld under § 192.241(c).
- (d) When nondestructive testing is required under § 192.241(b), the following percentages of each day's field butt welds, selected at random by the operator, must be nondestructively tested over their entire circumference:
 - (1) In Class 1 locations, at least 10 percent.
 - (2) In Class 2 locations, at least 15 percent.
 - (3) In Class 3 and 4 locations at crossings of major or navigable rivers and within railroad or public highway rights-of-way, including tunnels, bridges, and overhead road crossings, 100 percent unless impracticable, in which case at least 90 percent. Nondestructive testing must be impracticable for each girth weld not tested.
 - (4) At pipeline tie-ins, including tie-ins of replacement sections, 100 percent.
- (e) Except for a welder or welding operator whose work is isolated from the principal welding activity, a sample of each welder's or welding operator's work for each day must be nondestructively tested, when nondestructive testing is required under § 192.241(b).
- (f) When nondestructive testing is required under § 192.241(b) each operator must retain, for the life of the pipeline, a record showing by milepost, engineering station, or by geographic feature, the number of girth welds made, the number nondestructively tested, the number rejected, and the disposition of the rejects.

§ 192.245 Repair or Removal of Defects

- (a) Each weld that is unacceptable under § 192.241(c) must be removed or repaired. A weld must be removed if it has a crack that is more than 8 percent of the weld length.
- (b) Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability.
- (c) Repair of a crack, or of any defect in a previously repaired area must be in accordance

with the written weld repair procedures that have been qualified under § 192.225. Repair procedures must provide that the minimum mechanical properties specified for the welding procedures used to make the original weld are met upon completion of the final weld repair.

SUBPART F - JOINING OF MATERIALS OTHER THAN BY WELDING

§ 192.271 Scope

- (a) This subpart prescribes minimum requirements for joining materials in pipelines, other than by welding.
- (b) This subpart does not apply to joining during the manufacture of pipe or pipeline components.
- (c) Where pipe is to be joined or connections made by threaded couplings all threads will meet the standards of API Standard 5B. All joints will be made up power-tight using a suitable thread sealant.

§ 192.273 General

- (a) The pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading.
- (b) Each joint must be made in accordance with written procedures that have been proven by test or experience to produce strong gas-tight joints.
- (c) Each joint must be inspected to insure compliance with this subpart.

§ 192.275 Cast Iron Pipe

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

§ 192.277 Ductile Iron Pipe

- (a) Ductile iron pipe may not be joined by threaded joints.
- (b) Ductile iron pipe may not be joined by brazing.

§ 192.279 Copper Pipe

Copper pipe may not be threaded, except that copper pipe that is used for joining screw fittings or valves which may be threaded if the wall thickness is equivalent to the comparable size of Schedule 40 or heavier wall pipe listed in Table C1 of ASME/ANSI B16.5 ASME B36.10M (incorporated by reference, see § 192.7).

§ 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 D2564-12, for PVC (incorporated by reference, see § 192.7).
 - (3) The joint may not be heated or cooled to accelerate the setting of the cement.
 - (4) Plastic pipe manufactured from different materials shall not be joined by solvent cement joints.
- (c) *Heat-fusion joints.* Each heat-fusion joint on a PE pipe or component, except for electrofusion joints, must comply with ASTM F2620-12 (incorporated by reference in §192.7), or an alternative written procedure that has been demonstrated to provide an equivalent or superior level of safety and has been proven by tests or experience to produce strong gastight joints, and the following:
- (1) A butt heat-fusion joint must be joined by a device that holds the heater element square to the ends of the pipe or component, compresses the heated ends together, and holds the pipe in proper alignment in accordance with the appropriate procedure qualified under § 192.283.
 - (2) A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the pipe or component, uniformly and simultaneously, to establish the same temperature. The device used must be the same device specified in the operator's joining procedure for socket fusion.
 - (3) An electrofusion joint must be made using the equipment and techniques prescribed by the fitting manufacturer, or using equipment and techniques shown, by testing joints to the requirements of § 192.283(a)(1)(iii), to be equivalent to or better than the requirements of the fitting manufacturer.
 - (4) Heat may not be applied with a torch or other open flame.
- (d) *Adhesive joints.* Each adhesive joint on thermosetting plastic pipe must comply with the following:
- (1) The plastic fittings and adhesives must conform to the specifications listed in ASTM D2517 (incorporated by reference, see §192.7).
 - (2) The materials and adhesive must be compatible with each other.
- (e) *Mechanical joints.* Each compression type mechanical joint on plastic pipe must comply with the following:
- (1) Mechanical joints must be gas-tight and installed with materials that will prevent tensile pullouts.
 - (2) The gasket material in the coupling must be compatible with the plastic.
 - ~~(3)~~ (3) All mechanical fittings must meet a listed specification based upon the applicable material.
 - (4) (4) All mechanical joints or fittings installed after January 22, 2019, must be Category 1 as defined by a listed specification for the applicable material, providing a seal plus resistance to a force on the pipe joint equal to or greater than that which will cause no less than 25% elongation of pipe, or the pipe fails outside the joint area if tested in accordance with the applicable standard. Split tubular stiffeners shall not be used.

§ 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 that are made according to the procedure to the following tests, as applicable:
- (1) The test requirements of -
 - (i) In the case of thermoplastic pipe, based on the pipe material, the Sustained Pressure Test or the Minimum Hydrostatic Burst Test per the listed specification requirements. Additionally, for electrofusion joints, based on the pipe material, the Tensile Strength Test or the Joint Integrity Test per the listed specification.
 - (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 D2517-00 (incorporated by reference, see § 192.7).
 - (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 F1055-98(2006) (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, perform tensile testing in accordance with a listed specification. If the test specimen elongates no less than 25% or failure initiates outside the joint area, the procedure qualifies for use.
- (b) *Mechanical Joints.* Before any written procedure established under § 192.273(b) is used for making mechanical plastic pipe joints, the procedure must be qualified in accordance with a listed specification based upon the pipe material.
- (c) A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints.
- (d) Pipe or fittings manufactured before July 1, 1980 may be used in accordance with procedures that the manufacturer certifies will produce a joint as strong as the pipe.

§192.285 Plastic Pipe: Qualifying Persons To Make Joints.

- (a) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by:
- (1) Appropriate training or experience in the use of the procedure; and
 - (2) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (b) of this section.
- (b) The specimen joint must be:
- (1) Visually examined during and after assembly or joining and found to have the same

appearance as a joint or photographs of a joint that is acceptable under the procedure; and

- (2) In the case of a heat fusion, solvent cement, or adhesive joint;
 - (i) Tested under any one of the test methods listed under §192.283(a), and for PE heat fusion joints (except for electrofusion joints) visually inspected in accordance with ASTM F2620 (incorporated by reference, see § 192.7), or a written procedure that has been demonstrated to provide an equivalent or superior level of safety applicable to the type of joint and material being tested;
 - (ii) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or
 - (iii) Cut into at least three longitudinal straps, each of which is:
 - (A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and
 - (B) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.
- (c) A person must be re-qualified under an applicable procedure once each calendar year at intervals not exceeding 15 months, or after any production joint is found unacceptable by testing under §192.513.
- (d) Each operator shall establish a method to determine that each person making joints in plastic pipelines in the operator's system is qualified in accordance with this section.
- (e) For transmission pipe installed after July 1, 2021, records demonstrating each person's plastic pipe joining qualifications at the time of construction in accordance with this section must be retained for a minimum of 5 years following construction.

§ 192.287 Plastic Pipe: Inspection of Joints

No person may carry out the inspection of joints in plastic pipes required by §§ 192.273(c) and 192.285(b) unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.

SUBPART G - GENERAL CONSTRUCTION REQUIREMENTS FOR TRANSMISSION LINES AND MAINS

§ 192.301 Scope

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

§ 192.303 Compliance with Specifications or Standards

- (a) Each transmission line or main must be constructed in accordance with comprehensive written specifications or standards that are consistent with this Code. Applications or petitions for Certificates of Convenience and Necessity for new construction filed with the Arkansas Public Service Commission shall stipulate that design, construction, testing, operation and maintenance of facility will comply with the requirements of the Arkansas Gas Pipeline Code.
- (b) Each operator of a mobile home park, Federal housing development, or multi-building complex having a master meter, who constructs a distribution system must submit construction plans to the local gas operator for approval before construction is started. The plan shall show the following: location, type, size and specification of pipe; number of services; operating pressure; plans for corrosion control of the pipe, i.e., coating of pipe and cathodic protection. This review will assure all material and construction procedures meet the requirements of this Code. Each owner or operator must certify in writing to the operator supplying gas that the system shall be constructed, tested and inspected in accordance with this Code. This certification must be made to the gas operator before service is connected to the system and will be kept on file by each party for the life of the system.

§ 192.305 Inspection: General

Each transmission line or main must be inspected to ensure that it is constructed in accordance with this subpart. An operator must not use operator personnel to perform a required inspection if the operator personnel performed the construction task requiring inspection. Nothing in this section prohibits the operator from inspecting construction tasks with operator personnel who are involved in other construction tasks.

§ 192.307 Inspection of Materials

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

§ 192.309 Repair of Steel Pipe

- (a) Each imperfection or damage that impairs the serviceability of a length of steel pipe must be repaired or removed. If a repair is made by grinding, the remaining wall thickness must at least be equal to either:
 - (1) The minimum thickness required by the tolerances in the specification to which the pipe was manufactured; or
 - (2) The nominal wall thickness required for the design pressure of the pipeline.
- (b) Each of the following dents must be removed from steel pipe to be operated at a pressure

that produces a hoop stress of 20 percent, or more, of SMYS, unless the dent is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe:

- (1) A dent that contains a stress concentrator such as a scratch, gouge, groove, or arc burn.
- (2) A dent that affects the longitudinal weld or a circumferential weld.
- (3) In pipe to be operated at a pressure that produces a hoop stress of 40 percent or more of SMYS, a dent that has a depth of:
 - (i) More than 1/4 inch (6.4 millimeters) in pipe 12 3/4 inches (324 millimeters) or less in outer diameter; or
 - (ii) More than 2 percent of the nominal pipe diameter in pipe over 12 3/4 inches (324 millimeters) in outer diameter.

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

- (c) Each arc burn on steel pipe to be operated at a pressure that produces a hoop stress of 40 percent, or more, of SMYS must be repaired or removed. If a repair is made by grinding, the arc burn must be completely removed and the remaining wall thickness must be at least equal to either:
 - (1) The minimum wall thickness required by the tolerances in the specification to which the pipe was manufactured; or
 - (2) The nominal wall thickness required for the design pressure of the pipeline.
- (d) A gouge, groove, arc burn, or dent may not be repaired by insert patching or by pounding out.
- (e) Each gouge, groove, arc burn, or dent that is removed from a length of pipe must be removed by cutting out the damaged portion as a cylinder.

§ 192.311 Repair of Plastic Pipe

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

§ 192.313 Bends and Elbows

- (a) Each field bend in steel pipe, other than a wrinkle bend made in accordance with § 192.315, must comply with the following:
 - (1) A bend must not impair the serviceability of the pipe.
 - (2) Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage.
 - (3) On pipe containing the longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend unless:
 - (i) The bend is made with an internal bending mandrel; or
 - (ii) The pipe is 12 inches (305 millimeters) or less in outside diameter or has

a diameter to wall thickness ratio less than 70.

- (b) Each circumferential weld of steel pipe which is located where the stress during bending causes a permanent deformation in the pipe must be non-destructively tested either before or after the bending process.
- (c) Wrought-steel welding elbows and transverse segments of these elbows may not be used for changes in direction on steel pipe that is 2 inches (51 millimeters) or more in diameter unless the arc length, as measured along the crotch, is at least 1 inch (25 millimeters).
- (d) An operator may not install plastic pipe with a bend radius that is less than the minimum bend radius specified by the manufacturer for the diameter of the pipe being installed.

§ 192.315 Wrinkle Bends in Steel Pipe

- (a) A wrinkle bend may not be made on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent, or more, of SMYS.
- (b) Each wrinkle bend on steel pipe must comply with the following:
 - (1) The bend must not have any sharp kinks.
 - (2) When measured along the crotch of the bend, the wrinkles must be a distance of at least one pipe diameter.
 - (3) On pipe 16 inches (406 millimeters) or larger in diameter, the bend may not have a deflection of more than $1\ 1/2^\circ$ for each wrinkle.
 - (4) On pipe containing a longitudinal weld the longitudinal seam must be as near as practicable to the neutral axis of the bend.

§ 192.317 Protection from Hazards

- (a) The operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads.
- (b) Each aboveground transmission line or main must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.
- (c) Pipelines, including pipe risers in inland navigable waters must be protected from accidental damage by vessels.

§ 192.319 Installation of Pipe in a Ditch

- (a) When installed in a ditch, each transmission line that is to be operated at a pressure producing hoop stress of 20 percent or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage.
- (b) Each ditch for a transmission line or main must be backfilled in a manner that:
 - (1) Provides firm support under the pipe; and
 - (2) Prevents damage to the pipe and pipe coating from equipment or from the backfill material.
- (c) Promptly after a ditch for an onshore steel transmission line is backfilled (if the construction project involves 1,000 feet or more of continuous backfill length along the pipeline), but not later than 6 months after placing the pipeline in service, the operator must perform an assessment to assess any coating damage and ensure integrity of the coating using direct

current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology that provides comparable information about the integrity of the coating. Coating surveys must be conducted, except in locations where effective coating surveys are precluded by geographical, technical, or safety reasons.

- (d) An operator must notify PHMSA in accordance with § 192.18 at least 90 days in advance of using other technology to assess integrity of the coating under paragraph (dc) of this section.
- (e) An operator of an onshore steel transmission pipeline must develop a remedial action plan and apply for any necessary permits within 6 months of completing the assessment that identified the deficiency. An operator must repair any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dBµV for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within 6 months of the assessment, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after the receipt of permits.
- (f) An operator of an onshore steel transmission pipeline must make and retain for the life of the pipeline records documenting the coating assessment findings and remedial actions performed under paragraphs (d) through (f) of this section. An operator of an onshore steel transmission pipeline must develop a remedial action plan and apply for any necessary permits within 6 months of completing the assessment that identified the deficiency. An operator must repair any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dBµV for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within 6 months of the assessment, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after the receipt of permits. An operator of an onshore steel transmission pipeline must make and retain for the life of the pipeline records documenting the coating assessment findings and remedial actions performed under paragraphs (c) – (e) of this section.

§ 192.321 Installation of Plastic Pipe

- ~~(a) — The installation of plastic pipe must be carried out by, or under the direction of a person qualified by experience or training in the installation of plastic pipe. Procedures established by the operator or those recommended by the pipe manufacturer shall be followed during all phases of installation. Plastic pipe must be installed below ground level except as provided by paragraphs (g) and (h) and (i) of this section.~~
- (a) Plastic pipe must be installed below ground level except as provided by paragraphs (g) and (h) and (i) of this section.
- ~~(b) — Plastic pipe must be installed below ground level except as provided by paragraph (h) of this section.~~
- (b) Plastic pipe that is installed in a vault or any other below grade enclosure must be completely encased in gas-tight metal pipe and fittings that are adequately protected from corrosion.
- (c) Plastic pipe must be installed so as to minimize shear or tensile stresses.
- ~~(d) — Plastic pipe must have a minimum wall thickness in accordance with § 192.121. Thermoplastic pip that is not encased must have a minimum wall thickness of 00.090 inches (2.29 millimeters) except that pipe with an outside diameter of 0.875 inches (22.3 millimeters) or less may have a minimum wall thickness of 0.062 inches (1.58 millimeters).~~

~~(e)(d)~~ Plastic pipe must have a minimum wall thickness in accordance with § 192.121.

~~(f)(e)~~ Plastic pipe that is not encased must have an electrically conducting wire or other means of locating the pipe while it is underground. Tracer wire may not be wrapped around the pipe and contact with the pipe must be minimized but is not prohibited. Tracer wire or other metallic elements installed for pipe locating purposes must be resistant to corrosion damage, either by use of coated copper wire or by other means.

~~(f)~~ Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. Plastic pipe that is being encased must be protected from damage at all entrance and all exit points of the casing. The leading end of the plastic must be closed before insertion.

~~(g)~~ With written permission from the state Pipeline Safety Office, uncased plastic pipe may be temporarily installed above ground level under the following conditions:

~~(1)~~ The operator must be able to demonstrate that the cumulative aboveground exposure of the pipe does not exceed the manufacturer's recommended maximum period of exposure or 2 years, whichever is less.

~~(2)~~ The pipe either is located where damage by external forces is unlikely or is otherwise protected against such damage.

~~(3)~~ The pipe adequately resists exposure to ultraviolet light and high and low temperatures.

~~(g)~~ —

(h) Plastic pipe may be installed on bridges provided that it is:

(1) Installed with protection from mechanical damage, such as installation in a metallic casing;

(2) Protected from ultraviolet radiation; and

(3) Not allowed to exceed the pipe temperature limits specified in § 192.121.

(i) Plastic mains may terminate above ground level provided they comply with the following:

(1) The above-ground level part of the plastic main is protected against deterioration and external damage.

(2) The plastic main is not used to support external loads.

(3) Installations of risers at regulator stations must meet the design requirements of §192.204.

~~(j)~~ Uncased plastic pipe may be temporarily installed above ground level under the following conditions:

~~(1)~~ The operator must be able to demonstrate that the cumulative aboveground exposure of the pipe does not exceed the manufacturer's recommended maximum period of exposure or 2 years, whichever is less.

~~(2)~~ The pipe either is located where damage by external forces is unlikely or is otherwise protected against such damage.

~~(3)~~ The pipe adequately resists exposure to ultraviolet light and high and low temperatures.

§ 192.323 Casing

Each casing used on a transmission line or main under a railroad or highway must comply with the following:

- (a) The casing must be designed to withstand the superimposed loads.
- (b) If there is a possibility of water entering the casing, the ends must be sealed.
- (c) If the ends of an unvented casing are sealed and the sealing is strong enough to retain the maximum allowable operating pressure of the pipe, the casing must be designed to hold this pressure at a stress level of not more than 72 percent of SMYS.
- (d) If vents are installed on a casing, the vents must be protected from the weather to prevent water from entering the casing.

§ 192.325 Underground Clearance

- (a) Each transmission line must be installed with at least 12 inches (305 millimeters) of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, the transmission line must be protected from damage that might result from the proximity of the other structure.
- (b) Each main must be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures.
- (c) In addition to meeting the requirements of paragraph (a) or (b) of this section, each plastic transmission line or main must be installed with sufficient clearance, or must be insulated, from any source of heat so as to prevent the heat from impairing the serviceability of the pipe.
- (d) Each pipe-type or bottle-type holder must be installed with a minimum clearance from any other holder as prescribed in § 192.175(b).

§ 192.327 Cover

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

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

- (b) Except as provided in paragraphs (c) and (d) of this section, each buried main must be

- installed with at least 24 inches (610 millimeters) of cover.
- (c) Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.
 - (d) A main may be installed with less than 24 inches (610 millimeters) of cover if the law of the State or municipality:
 - (1) Establishes a minimum cover of less than 24 inches (610 millimeters);
 - (2) Requires that mains be installed in a common trench with other utility lines; and
 - (3) Provides adequately for prevention of damage to the pipe by external forces.
 - (e) Except as provided in paragraph (c) of this section, all pipe installed in a navigable river, stream, or harbor must be installed with a minimum cover of 48 inches (1,219 millimeters) in soil or 24 inches (610 millimeters) in consolidated rock between the top of the pipe and the underwater natural bottom (as determined by recognized and generally accepted practices).

§ 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.

§192.329 Installation Of Plastic Pipelines By Trenchless Excavation.

Plastic pipelines installed by trenchless excavation must comply with the following:

- (a) Each operator must take practicable steps to provide sufficient clearance for installation and maintenance activities from other underground utilities and/or structures at the time of installation.
- (b) For each pipeline section, plastic pipe and components that are pulled through the ground must use a weak link, as defined by §192.3, to ensure the pipeline will not be damaged by any excessive forces during the pulling process.

SUBPART H - CUSTOMER METERS, SERVICE REGULATORS, AND SERVICE LINES

§ 192.351 Scope

This subpart prescribes minimum requirements for installing customer meters, service regulators, service lines, service line valves, and service line connections to mains.

§ 192.353 Customer Meters and Regulators: Location

- (a) Each meter and service regulator, whether inside or outside a building, must be installed in a readily accessible location and be protected from corrosion and other damage, including, if installed outside a building, vehicular damage that may be anticipated.
- (b) Each service regulator installed within a building must be located as near as practical to the point of service line entrance.
- (c) Each meter installed within a building must be located in a ventilated place and not less than 3 feet (914 millimeters) from any source of ignition or any source of heat which might damage the meter.
- (d) Where feasible, meters and regulators previously installed inside of buildings will be relocated to outside of building when the regulator or meter is removed for any reason.

§ 192.355 Customer Meters and Regulators: Protection from Damage

- (a) *Protection from vacuum or back pressure.* If the customer's equipment might create either a vacuum or a back pressure, a device must be installed to protect the system.
- (b) *Service regulator vents and relief vents.* Service regulator vents and relief vents must terminate outdoors, and the outdoor terminal must—
 - (1) Be rain and insect resistant;
 - (2) Be located at a place where gas from the vent can escape freely into the atmosphere and away from any opening into the building; and
 - (3) Be protected from damage caused by submergence in areas where flooding may occur.
- (c) *Pits and vaults.* Each pit or vault that houses a customer meter or regulator at a place where vehicular traffic is anticipated, must be able to support that traffic.

§ 192.357 Customer Meters and Regulators: Installation

- (a) Each meter and each regulator must be installed so as to minimize anticipated stresses upon the connecting piping and the meter.
- (b) When close all-thread nipples are used, the wall thickness remaining after the threads are cut must meet the minimum wall thickness requirements of this part.
- (c) Connections made of lead or other easily damaged material may not be used in the installation of meters or regulators.
- (d) Each regulator that might release gas in its operation must be vented to the outside

atmosphere.

§ 192.359 Customer Meter Installations: Operating Pressure

- (a) A meter may not be used at a pressure that is more than 67 percent of the manufacturer's shell test pressure.
- (b) Each newly installed meter manufactured after November 12, 1970, must have been tested to a minimum of 10 p.s.i. (69 kPa) gage.
- (c) A rebuilt or repaired tinned steel case meter may not be used at a pressure that is more than 50 percent of the pressure used to test the meter after rebuilding or repairing.

§ 192.361 Service Lines: Installation

- (a) *Depth.* Each buried service line must be installed with at least 12 inches (305 millimeters) of cover in private property and at least 18 inches (457 millimeters) of cover in streets and roads. However, where an underground structure prevents installation at those depths, the service line must be able to withstand any anticipated external load.
- (b) *Support and backfill.* Each service line must be properly supported on undisturbed or well- compacted soil, and material used for backfill must be free of materials that could damage the pipe or its coating.
- (c) *Grading for drainage.* Where condensate in the gas might cause interruption in the gas supply to the customer, the service line must be graded so as to drain into the main or into drips at the low points in the service line.
- (d) *Protection against piping strain and external loading.* Each service line must be installed so as to minimize anticipated piping strain and external loading.
- (e) *Installation of service lines into buildings.* Each underground service line installed below grade through the outer foundation wall of a building must:
 - (1) In the case of a metal service line, be protected against corrosion;
 - (2) In the case of plastic service line, be protected from shearing action and backfill settlement; and
 - (3) Be sealed at the foundation wall to prevent leakage into the building.
- (f) *Installation of service lines under buildings.* Where an underground service line is installed under a building;
 - (1) It must be encased in a gas tight conduit;
 - (2) The conduit and the service line must, if the service line supplies the building it underlies, extend into a normally usable and accessible part of the building; and
 - (3) The space between the conduit and the service line must be sealed to prevent gas leakage into the building and, if the conduit is sealed at both ends, a vent line from the annular space must extend to a point where gas would not be a hazard, and extend above grade, terminating in a rain and insect resistant fitting.
- (g) *Locating underground service lines.* Each underground nonmetallic service line that is not encased must have a means of locating the pipe that complies with § 192.321(~~fe~~).
- (h) *Service lines installed by other than gas company personnel.* These person(s) shall certify to the gas company that the line(s) were installed in accordance with this code.

§ 192.363 Service Lines: Valve Requirements

- (a) Each service line must have a service-line valve that meets the applicable requirements of Subparts B and D of this part. A valve incorporated in a meter bar, that allows the meter to be bypassed, may not be used as a service-line valve.
- (b) A soft seat service line valve may not be used if its ability to control the flow of gas could be adversely affected by exposure to anticipated heat.
- (c) Each service-line valve on a high-pressure service line, installed above ground or in an area where the blowing of gas would be hazardous, must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools.

§ 192.365 Service Lines: Location of Valves

- (a) *Relation to regulator or meter.* Each service-line valve must be installed upstream of the regulator or, if there is no regulator, upstream of the meter.
- (b) *Outside valves.* Each service line must have a shut-off valve in a readily accessible location that, if feasible, is outside of the building.
- (c) *Underground valves.* Each underground service-line valve must be located in a covered durable curb box or standpipe that allows ready operation of the valve and is supported independently of the service lines.

§ 192.367 Service Lines: General Requirements for Connections to Main Piping

- (a) *Location.* Each service line connection to a main must be located at the top of the main or, if that is not practical, at the side of the main, unless a suitable protective device is installed to minimize the possibility of dust and moisture being carried from the main into the service line.
- (b) *Compression-type connection to mains.* Each compression-type service line to main connection must:
 - (1) Be designed and installed to effectively sustain the longitudinal pull-out or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading;
 - (2) If gaskets are used in connecting the service line to the main connection fitting, have gaskets that are compatible with the kind of gas in the system;and
 - (3) If used on pipelines comprised of plastic, be a Category 1 connection as defined by a listed specification for the applicable material, providing a seal plus resistance to a force on the pipe joint equal to or greater than that which will cause no less than 25% elongation of pipe, or the pipe fails outside the joint area if tested in accordance with the applicable standard.

§ 192.369 Service Lines: Connection to Cast Iron or Ductile Iron Mains

- (a) Each service line connected to a cast iron or ductile iron main must be connected by a mechanical clamp, by drilling and tapping the main, or by another method meeting the requirements of § 192.273.
- (b) If a threaded tap is being inserted, the requirements of §§ 192.151(b) and (c) must also be met.

§ 192.371 Service Lines: Steel

Each steel service line to be operated at less than 100 p.s.i. (689 kPa) gage must be constructed

of pipe designed for a minimum of 100 p.s.i. (689 kPa) gage.

§ 192.373 Service Lines: Cast Iron and Ductile Iron

- (a) Cast or ductile iron pipe less than 6 inches (152 millimeters) in diameter may not be installed for service lines.
- (b) If cast iron pipe or ductile iron pipe is installed for use as a service line, the part of the service line which extends through the building wall must be of steel pipe.
- (c) A cast iron or ductile iron service line may not be installed in unstable soil or under a building.

§ 192.375 Service Lines: Plastic

- (a) Each plastic service line outside a building must be installed below ground level, except that it may terminate above the ground and outside the building, if:
 - (1) The above ground part of the plastic service line is protected against deterioration and external damage; and
 - (2) It may terminate above ground level and outside the building, if -
 - (i) The above ground level part of the plastic service line is protected against deterioration and external damage;
 - (ii) The plastic service line is not used to support external loads; and
 - (iii) The riser portion of the service line meets the design requirements of §192.204.

Each plastic service line inside a building must be protected from external damage.

§ 192.376 Installation Of Plastic Service Lines By Trenchless Excavation

Plastic service lines installed by trenchless excavation must comply with the following:

- (a) Each operator shall take practicable steps to provide sufficient clearance for installation and maintenance activities from other underground utilities and structures at the time of installation.
- (b) For each pipeline section, plastic pipe and components that are pulled through the ground must use a weak link, as defined by §192.3, to ensure the pipeline will not be damaged by any excessive forces during the pulling process.

§ 192.377 Service Lines: Copper

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

§ 192.379 New Service Lines Not in Use

Each service line that is not placed in service upon completion of installation must comply with one of the following until the customer is supplied with gas:

- (a) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.
- (b) A mechanical device or fitting that will prevent the flow of gas must be installed in the

service line or in the meter assembly.

- (c) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

§ 192.381 Service Lines: Excess Flow Valve Performance Standards

- (a) Excess flow valves (EFVs) to be used on service lines that operate continuously throughout the year at a pressure not less than 10 p.s.i. (69 kPa) gage must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer's specification, to ensure that each valve will:
 - (1) Function properly up to the maximum operating pressure at which the valve is rated;
 - (2) Function properly at all temperatures reasonably expected in the operating environment of the service line;
 - (3) At 10 p.s.i. (69 kPa) gage:
 - (i) Close at, or not more than 50 percent above, the rated closure flow rate specified by the manufacturer; and
 - (ii) Upon closure, reduce gas flow -
 - (A) For an excess flow valve designed to allow pressure to equalize across the valve, to no more than 5 percent of the manufacturer's specified closure flow rate, up to a maximum of 20 cubic feet per hour (0.57 cubic meters per hour); or
 - (B) For an excess flow valve designed to prevent equalization of pressure across the valve, to no more than 0.4 cubic feet per hour (.01 cubic meters per hour); and
 - (4) Not to close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate.
- (b) An excess flow valve must meet the applicable requirements of subparts B and D of this part.
- (c) An operator must mark or otherwise identify the presence of an excess flow valve in the service line.
- (d) An operator shall locate an excess flow valve as near as practical to the fitting connecting the service line to its source of gas supply.
- (e) An operator should not install an excess flow valve on a service line where the operator has prior experience with contaminants in the gas stream, where these contaminants could be expected to cause the excess flow valve to malfunction or where the excess flow valve would interfere with the necessary operation and maintenance activities on the service, such as blowing liquids from the line.

§ 192.383 Excess Flow Valve Installation

- (a) Definitions. As used in this section:

Branched service line means a gas service line that begins at the existing service line or is installed concurrently with the primary service line but serves a separate residence.

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 (SFR).

- (b) *Installation required.* An EFV installation must comply with the performance standards in §192.381. After April 14, 2017, each operator must install an EFV on any new or replace service line serving the following types of services before the line is activated:
- (1) A single service line to one SFR;
 - (2) A branched service line to a SFR installed concurrently with the primary SFR service line (i.e., a single EFV may be installed to protect both service lines);
 - (3) A branched service line to a SFR installed off a previously installed SFR service line that does not contain an EFV;
 - (4) Multifamily residences with known customer loads not exceeding 1,000 SCFH per service, at time of service installation based on installed meter capacity, and
 - (5) A single, small commercial customer served by a single service line with a known customer load not exceeding 1,000 SCFH, at the time of meter installation, based on installed meter capacity.
- (c) *Exceptions to excess flow valve installation requirement.* An operator need not install an excess flow valve if one or more of the following conditions are 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 customer;
 - (3) An EFV could interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or
 - (4) An EFV meeting the performance standards in § 192.381 is not commercially available to the operator.
- (d) *Customer's right to request an EFV.* Existing service line customers who desire an EFV on service lines not exceeding 1,000 SCFH and who do not qualify for one of the exceptions in paragraph (c) of this section may request an EFV to be installed on their service lines. If an eligible service line customer requests an EFV installation, an operator must install the EFV at a mutually agreeable date. The operator's rate-setter determines how and to whom the costs of the requested EFVs are distributed.
- (e) *Operator notification of customers concerning EFV installation.* Operators must notify customers of their right to request an EFV in the following manner:
- (1) Except as specified in paragraphs (c) and (e)(5) of this section, each operator must provide written or electronic notification to customers of their right to request the installation of an EFV. Electronic notification can include emails, Web site postings, and e-billing notices.
 - (2) The notification must include an explanation for the service line customer of the potential safety benefits that may be derived from installing an EFV. The explanation must include information that an EFV is designed to shut off the flow of natural gas automatically if the service line breaks.

- (3) The notification must include a description of EFV installation and replacement costs. The notice must alert the customer that the costs for maintaining and replacing an EFV may later be incurred, and what those costs will be to the extent known.
- (4) The notification must indicate that if a service line customer requests installation of an EFV and the load does not exceed 1,000 SCFH and the conditions of paragraph (c) are not present, the operator must install an EFV at a mutually agreeable date.
- (5) Operators of master-meter systems and liquefied petroleum gas (LPG) operators with fewer than 100 customers may continuously post a general notification in a prominent location frequented by customers.
- (f) *Operator evidence of customer notification.* An operator must make a copy of the notice or notices currently in use available during PHMSA inspections or State inspections conducted under a pipeline safety program certified or approved by PHMSA under 49 U.S.C. 60105 or 60106.
- (g) *Reporting.* Except for operators of master-meter systems and LPG operators with fewer than 100 customers, each operator must report the EFV measures detailed in the annual report required by § 191.11.

§ 192.385 Manual service line shut-off valve installation.

- (a) *Definitions.* As used in this section:
Manual service line shut-off valve means a curb valve or other manually operated valve located near the service line that is safely accessible to operator personnel or other personnel authorized by the operator to manually shut off gas flow to the service line, if needed.
- (b) *Installation requirement.* The operator must install either a manual service line shut-off valve or, if possible, based on sound engineering analysis and availability, an EFV for any new or replaced service line with installed meter capacity exceeding 1,000 SCFH.
- (c) *Accessibility and maintenance.* Manual service line shut-off valves for any new or replaced service line must be installed in such a way as to allow accessibility during emergencies. Manual service shut-off valves installed under this section are subject to regular scheduled maintenance, as documented by the operator and consistent with the valve manufacturer's specification.

SUBPART I - REQUIREMENTS FOR CORROSION CONTROL

§ 192.451 Scope

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

§ 192.452 How does this subpart apply to converted pipelines and regulated onshore gathering lines?

- (a) *Converted pipelines.* Notwithstanding the date the pipeline was installed or any earlier deadlines for compliance, each pipeline which qualifies for use under this part in

accordance with § 192.14 must meet the requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, and all other applicable requirements within 1 year after the pipeline is readied for service. However, the requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply if the pipeline substantially meets those requirements before it is readied for service or it is a segment which is replaced, relocated, or substantially altered.

- (b) ~~Regulated onshore gathering lines. Type A and B onshore gathering lines.~~ For any **Type A and Type B** regulated onshore gathering line under § 192.9 existing on April 14, 2006, that was not previously subject to this part, and for any onshore gathering line that becomes a regulated onshore gathering line under § 192.9 after April 14, 2006, because of a change in class location or increase in dwelling density:
 - (1) The requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, apply to the gathering line regardless of the date the pipeline was actually installed; and
 - (2) The requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply only if the pipeline substantially meets those requirements.
- (c) Type C onshore regulated gathering lines. For any Type C onshore regulated gathering pipeline under § 192.9 existing on May 16, 2022, that was not previously subject to this part, and for any Type C onshore gas gathering pipeline that becomes subject to this subpart after May 16, 2022, because of an increase in MAOP, change in class location, or presence of a building intended for human occupancy or other impacted site:
 - (1) The requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, apply to the gathering line regardless of the date the pipeline was actually installed; and
 - (2) The requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply only if the pipeline substantially meets those requirements.
- (d) Regulated onshore gathering lines generally. Any gathering line that is subject to this subpart per § 192.9 at the time of construction must meet the requirements of this subpart applicable to pipelines installed after July 31, 1971.

§ 192.453 General

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

§ 192.455 External Corrosion Control: Buried or Submerged Pipelines Installed After July 31, 1971

- (a) Except as provided in paragraphs (b), (c), (f), and (g) of this section, each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following:
 - (1) It must have an external protective coating meeting the requirements of § 192.461.
 - (2) It must have a cathodic protection system designed to protect the pipeline in its entirety in accordance with this subpart, installed and placed in operation within one year after completion of construction.

- (b) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience in the area of application, including, as a minimum, soil resistivity measurements and tests for corrosion accelerating bacteria, that a corrosive environment does not exist. However, within 6 months after an installation made pursuant to the preceding sentence, the operator shall conduct tests, including pipe-to-soil potential measurements with respect to either a continuous reference electrode or an electrode using close spacing, not to exceed 20 feet (6 meters), and soil resistivity measurements at potential profile peak locations, to adequately evaluate the potential profile along the entire pipeline. If the tests made indicate that a corrosive condition exists, the pipeline must be cathodically protected in accordance with paragraph (a)(2) of this section.
- (c) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience that:
 - (1) For a copper pipeline, a corrosive environment does not exist; or
 - (2) For a temporary pipeline with an operating period of service not to exceed 5 years beyond installation, corrosion during the 5- year period of service of the pipeline will not be detrimental to public safety.
- (d) Notwithstanding the provisions of paragraph (b) or (c) of this section, if a pipeline is externally coated, it must be cathodically protected in accordance with paragraph (a)(2) of this section.
- (e) Aluminum may not be installed in a buried or submerged pipeline if that aluminum is exposed to an environment with a natural pH in excess of 8, unless tests or experience indicates its suitability in the particular environment involved.
- (f) This section does not apply to electrically isolated, metal alloy fittings in plastic pipelines if:
 - (1) For the size fitting to be used, an operator can show by tests, investigation, or experience in the area of application, that adequate corrosion control is provided by the alloy composition; and
 - (2) The fitting is designed to prevent leakage caused by localized corrosion pitting.
- (g) Electrically isolated metal alloy fittings installed after January 22, 2019, that do not meet the requirements of paragraph (f) must be cathodically protected, and must be maintained in accordance with the operator's integrity management plan.

§ 192.457 External Corrosion Control: Buried or Submerged Pipelines Installed Before August 1, 1971

- (a) Except for buried piping at compressor, regulator, and measuring stations, each buried or submerged transmission line installed before August 1, 1971, that has an effective external coating must be cathodically protected along the entire area that is effectively coated, in accordance with this subpart. For the purposes of this subpart, a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The operator shall make tests to determine the cathodic protection current requirements.
- (b) Except for cast iron or ductile iron, each of the following buried or submerged pipelines installed before August 1, 1971, must be cathodically protected in accordance with this subpart in areas in which active corrosion is found:

- (1) Bare or ineffectively coated transmission lines.
- (2) Bare or coated pipes at compressor, regulator, and measuring stations.
- (3) Bare or coated distribution lines.

§ 192.459 External Corrosion Control: Examination of Buried Pipeline when Exposed

Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion, if bare or the coating is deteriorated, must be examined for evidence of external corrosion. If external corrosion requiring remedial action under §§ 192.483 through 192.489 is found, the operator shall investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

§ 192.461 External Corrosion Control: Protective Coating

- (a) Each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must:
 - (1) Be applied on a properly prepared surface;
 - (2) Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture;
 - (3) Be sufficiently ductile to resist cracking;
 - (4) Have sufficient strength to resist damage due to handling (including, but not limited to, transportation, installation, boring, and backfilling) and soil stress; and
 - (5) Have properties compatible with any supplemental cathodic protection.
- (b) Each external protective coating which is an electrically insulating type must also have low moisture absorption and high electrical resistance.
- (c) Each external protective coating must be inspected just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired.
- (d) Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.
- (e) If coated pipe is installed by boring, driving, or other similar methods, precautions must be taken to minimize damage to the coating during installation.
- (f) Promptly after the backfill of an onshore steel transmission pipeline ditch following repair or replacement (if the repair or replacement results in 1,000 feet or more of backfill length along the pipeline), but no later than 6 months after the backfill, the operator must perform an assessment to assess any coating damage and ensure integrity of the coating using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology that provides comparable information about the integrity of the coating. Coating surveys must be conducted, except in locations where effective coating surveys are precluded by geographical, technical, or safety reasons.

- (g) An operator must notify PHMSA in accordance with § 192.18 at least 90 days in advance of using other technology to assess integrity of the coating under paragraph (f) of this section.
- (h) An operator of an onshore steel transmission pipeline must develop a remedial action plan and apply for any necessary permits within 6 months of completing the assessment that identified the deficiency. The operator must repair any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dBuV for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within 6 months of the assessment, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after the receipt of permits.
- (i) An operator of an onshore steel transmission pipeline must make and retain for the life of the pipeline records documenting the coating assessment findings and remedial actions performed under paragraphs (f) through (h) of this section.

§ 192.463 External Corrosion Control: Cathodic Protection

- (a) Each cathodic protection system required by this subpart must provide a level of cathodic protection that complies with one or more of the applicable criteria contained in Appendix D of this subpart. If none of these criteria is applicable, the cathodic protection system must provide a level of cathodic protection at least equal to that provided by compliance with one or more of these criteria.
- (b) If amphoteric metals are included in a buried or submerged pipeline containing a metal of different anodic potential:
 - (1) The amphoteric metals must be electrically isolated from the remainder of the pipeline and cathodically protected; or
 - (2) The entire buried or submerged pipeline must be cathodically protected at a cathodic potential that meets the requirements of Appendix D of this part for amphoteric metals.
- (c) The amount of cathodic protection must be controlled so as not to damage the protective coating or the pipe.

§ 192.465 External Corrosion Control: Monitoring

- (a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of § 192.463. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of 100 feet (30 meters), or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period.
- (b) Cathodic protection rectifiers and impressed current power sources must be periodically inspected as follows:
 - (1) Each cathodic protection rectifier or impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2 ½ months between inspections, to ensure adequate amperage and voltage levels needed to provide cathodic protection are maintained. This may be done either

through remote measurement or through an onsite inspection of the rectifier.

- (2) After January 1, 2022, each remotely inspected rectifier must be physically inspected for continued safe and reliable operation at least once each calendar year, but with intervals not exceeding 15 months.
- (c) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance six times each calendar year, but with intervals not exceeding 2 1/2 months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.
- (d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the 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.

§ 192.467 External Corrosion Control: Electrical Isolation

- (a) Each buried or submerged pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.
- (b) One or more insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.
- (c) Except for unprotected copper inserted in ferrous pipe, each pipeline must be electrically isolated from metallic casings that are a part of the underground system. However, if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing.
- (d) Inspection and electrical tests must be made to assure that electrical isolation is adequate.
- (e) An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.
- (f) Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.

§ 192.469 External Corrosion Control: Test Stations

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

§ 192.471 External Corrosion Control: Test Leads

- (a) Each test lead wire must be connected to the pipeline so as to remain mechanically secure

and electrically conductive.

- (b) Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe.
- (c) Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

§ 192.473 External Corrosion Control: Interference Currents

- (a) Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of such currents.
- (b) Each impressed current type cathodic protection system or galvanic anode system must be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures.
- (c) For onshore gas transmission pipelines, the program required by paragraph (a) of this section must include:
 - (1) Interference surveys for a pipeline system to detect the presence and level of any electrical stray current. Interference surveys must be conducted when potential monitoring indicates a significant increase in stray current, or when new potential stray current sources are introduced, such as through co-located pipelines, structures, or high voltage alternating current (HVAC) power lines, including from additional generation, a voltage up-rating, additional lines, new or enlarged power substations, or new pipelines or other structures;
 - (2) Analysis of the results of the survey to determine the cause of the interference and whether the level could cause significant corrosion, impede safe operation, or adversely affect the environment or public;
 - (3) Development of a remedial action plan to correct any instances where interference current is greater than or equal to 100 amps per meter squared alternating current (AC), or if it impedes the safe operation of a pipeline, or if it may cause a condition that would adversely impact the environment or the public; and
 - (4) Application for any necessary permits within 6 months of completing the interference survey that identified the deficiency. An operator must complete remedial actions promptly, but no later than the earliest of the following: within 15 months after completing the interference survey that identified the deficiency; or as soon as practicable, but not to exceed 6 months, after obtaining any necessary permits.

§ 192.475 Internal Corrosion Control: General

- (a) Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.
- (b) Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. If internal corrosion is found:
 - (1) The adjacent pipe must be investigated to determine the extent of internal corrosion;
 - (2) Replacement must be made to the extent required by the applicable

paragraphs of §§ 192.485, 192.487, or 192.489; and

- (3) Steps must be taken to minimize the internal corrosion.
- (c) Gas containing more than 0.1 grain of hydrogen sulfide per 100 cubic feet (2.32 milligrams/m³) at standard conditions may not be stored in pipe-type or bottle-type holders.

§ 192.476 Internal Corrosion Control: Design and Construction of Transmission Line

- (a) *Design and construction.* Except as provided in paragraph (b) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must have features incorporated into its design and construction to reduce the risk of internal corrosion. At a minimum, unless it is impracticable or unnecessary to do so, each new transmission line or replacement of line pipe, valve, fitting or other line component in a transmission line must:
 - (1) Be configured to reduce the risk that liquids will collect in the line;
 - (2) Have effective liquid removal features whenever the configuration would allow liquids to collect; and
 - (3) Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion.
- (b) *Exceptions to applicability.* The design and construction requirements of paragraph (a) of this section do not apply to the following:
 - (1) Offshore pipeline; and
 - (2) Pipeline installed or line pipe, valve, fitting or other line component replaced before May 23, 2007.
- (c) *Change to existing transmission line.* When an operator changes the configuration of a transmission line, the operator must evaluate the impact of the change on internal corrosion risk to the downstream portion of an existing onshore transmission line and provide for removal of liquids and monitoring of internal corrosion as appropriate.
- (d) *Records.* An operator must maintain records demonstrating compliance with this section. Provided the records show why incorporating design features addressing paragraph (a)(1), (a)(2), or (a)(3) of this section is impracticable or unnecessary, an operator may fulfill this requirement through written procedures supported by as-built drawings or other construction records.

§ 192.477 Internal Corrosion Control: Monitoring

If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with intervals not exceeding 7 1/2 months.

§ 192.478 Internal corrosion control: Onshore transmission monitoring and mitigation.

- (a) Each operator of an onshore gas transmission pipeline with corrosive constituents in the gas being transported must develop and implement a monitoring and mitigation program to mitigate the corrosive effects, as necessary. Potentially corrosive constituents include, but are not limited to: carbon dioxide, hydrogen sulfide, sulfur, microbes, and liquid water, either by itself or in combination. An operator must evaluate the partial pressure of each corrosive constituent, where applicable, by itself or in combination, to evaluate the effect of the corrosive constituents on the internal corrosion of the pipe and implement mitigation

measures as necessary.

(b) The monitoring and mitigation program described in paragraph (a) of this section must include:

(1) The use of gas-quality monitoring methods at points where gas with potentially corrosive contaminants enters the pipeline to determine the gas stream constituents.

(2) Technology to mitigate the potentially corrosive gas stream constituents. Such technologies may include product sampling, inhibitor injections, in-line cleaning pigging, separators, or other technology that mitigates potentially corrosive effects.

(3) An evaluation at least once each calendar year, at intervals not to exceed 15 months, to ensure that potentially corrosive gas stream constituents are effectively monitored and mitigated.

(c) An operator must review its monitoring and mitigation program at least once each calendar year, at intervals not to exceed 15 months, and based on the results of its monitoring and mitigation program, implement adjustments, as necessary.

§ 192.479 Atmospheric Corrosion Control: General

- (a) Each operator must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under paragraph (c) of this section.
- (b) Coating material must be suitable for the prevention of atmospheric corrosion.
- (c) Except portions of pipelines in offshore splash zones or soil-to-air interfaces, the operator need not protect from atmospheric corrosion any pipeline for which the operator demonstrates by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will--
 - (1) Only be a light surface oxide; or
 - (2) Not affect the safe operation of the pipeline before the next scheduled inspection.

§ 192.481 Atmospheric Corrosion Control: Monitoring

- (a) Each operator must inspect and evaluate each pipeline or portion of the pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

Pipeline type:	Then the frequency of inspection is:
(1) Onshore other than a Service Line	At least once every 3 calendar years, but with intervals not exceeding 39 months.
(2) Onshore Service Line	At least once every 5 calendar years, but with intervals not exceeding 63 months, except as provided in paragraph (d) of this section.
(3) Offshore	At least once each calendar year, but with intervals not exceeding 15 months.

- (b) During inspections the operator must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.
- (c) If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by § 192.479.

- (d) If atmospheric corrosion is found on a service line during the most recent inspection, then the next inspection of that pipeline or portion of pipeline must be within 3 calendar years, but with intervals not exceeding 39 months.

§ 192.483 Remedial Measures: General

- (a) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of § 192.461.
- (b) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected in accordance with this subpart.
- (c) Except for cast iron or ductile iron pipe, each segment of buried or submerged pipe that is required to be repaired because of external corrosion must be cathodically protected in accordance with this subpart.

§ 192.485 Remedial Measures: Transmission Lines

- (a) *General corrosion.* Each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for the MAOP of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.
- (b) *Localized corrosion pitting.* Each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.
- (c) ~~Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G (incorporated by reference, see § 192.7) or the procedure in PRCI PR 3-805 (R-STRENG) (incorporated by reference, see § 192.7). Both procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations prescribed in the procedures.~~ Calculating remaining strength. Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness must be determined and documented in accordance with § 192.712.

§ 192.487 Remedial Measures: Distribution Lines Other Than Cast Iron or Ductile Iron Lines

- (a) *General corrosion.* Except for cast iron or ductile iron pipe, each segment of generally corroded distribution line pipe with a remaining wall thickness less than that required for the MAOP of the pipeline, or a remaining wall thickness less than 30 percent of the nominal wall thickness, must be replaced. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.
- (b) *Localized corrosion pitting.* Except for cast iron or ductile iron pipe, each segment of distribution line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired.

§ 192.489 Remedial Measures: Cast Iron and Ductile Iron Pipelines

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

§ 192.490 Direct Assessment

Each operator that uses direct assessment as defined in § 192.903 on an onshore transmission line made primarily of steel or iron to evaluate the effects of a threat in the first column must carry out the direct assessment according to the standard listed in the second column. These standards do not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process.

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

§ 192.491 Corrosion Control Records

- (a) Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system. Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.
- (b) Each record or map required by paragraph (a) of this section must be retained for as long as the pipeline remains in service.
- (c) Each operator shall maintain a record of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least 5 years with the following exceptions:
 - (1) Operators must retain records related to §§ 192.465(a) and (e) and 192.475(b) for as long as the pipeline remains in service.
 - (2) Operators must retain records of the two most recent atmospheric corrosion inspections for each distribution service line that is being inspected under the interval in §192.481(a)(2).

§ 192.493 In-Line Inspection of Pipelines

When conducting in-line inspections of pipelines required by this part, an operator must comply with API STD 1163, ANSI/ASNT ILI-PQ, and NACE SP0102, (incorporated by reference, see § 192.7). Assessments may be conducted using tethered or remotely controlled tools, not explicitly discussed

in NACE SP0102, provided they comply with those sections of NACE SP0102 that are applicable.

| _____

SUBPART J - TEST REQUIREMENTS

§ 192.501 Scope

This subpart prescribes minimum leak-test and strength-test requirements for pipelines.

§ 192.503 General Requirements

- (a) No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until:
 - (1) It has been tested in accordance with this subpart and § 192.619 to substantiate the maximum allowable operating pressure; and
 - (2) Each detected leak has been eliminated.
- (b) The test medium must be liquid, air, natural gas, or inert gas that is:
 - (1) Compatible with the material of which the pipeline is constructed;
 - (2) Relatively free of sedimentary materials; and
 - (3) Except for natural gas, nonflammable.
- (c) Except as provided in § 192.505(a), if air, natural gas, or inert gas is used as the test medium, the following maximum hoop stress limitations apply:

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

- (d) Each joint used to tie-in a test segment of pipeline is excepted from the specific test requirements of this subpart, but each non-welded joint must be leak tested at not less than its operating pressure.
- (e) If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required, if the manufacturer of the component certifies that:
 - (1) The component was tested to at least the pressure required for the pipeline to which it is being added;
 - (2) The component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added; or
 - (3) The component carries a pressure rating established through applicable ASME/ANSI, Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS) specifications, or by unit strength calculations as described in § 192.143.

§ 192.505 Strength Test Requirements for Steel Pipeline to Operate at a Hoop Stress of 30 Percent or More of SMYS

- (a) Except for service lines, each segment of a steel pipeline that is to operate at a hoop stress of 30 percent or more of SMYS must be strength tested in accordance with this section to substantiate the proposed maximum allowable operating pressure. In addition, in a Class 1 or Class 2 location, if there is a building intended for human occupancy within 300 feet (91 meters) of a pipeline, a hydrostatic test must be conducted to a test pressure of at least 125 percent of maximum operating pressure on that segment of the pipeline within 300 feet (91 meters) of such a building, but in no event may the test section be less than 600 feet (183 meters) unless the length of the newly installed or relocated pipe is less than 600 feet (183 meters). However, if the buildings are evacuated while the hoop stress exceeds 50 percent of SMYS, air or inert gas may be used as the test medium.
- (b) In a Class 1 or Class 2 location, each compressor station, regulator station, and measuring station, must be tested to at least Class 3 location test requirements.
- (c) Except as provided in paragraph (d) of this section, the strength test must be conducted by maintaining the pressure at or above the test pressure for at least 8 hours.
- (d) For fabricated units and short sections of pipe, for which a post installation test is impractical, a preinstallation strength test must be conducted by maintaining the pressure at or above the test pressure for at least 4 hours.

§ 192.506 Transmission Lines: Spike Hydrostatic Pressure Test

- (a) *Spike test requirements.* Whenever a segment of steel transmission pipeline that is operated at a hoop stress level of 30 percent or more of SMYS is spike tested under this part, the spike hydrostatic pressure test must be conducted in accordance with this section.
 - (1) The test must use water as the test medium.
 - (2) The baseline test pressure must be as specified in the applicable paragraphs of § 192.619(a)(2) or § 192.620(a)(2), whichever applies.
 - (3) The test must be conducted by maintaining a pressure at or above the baseline test pressure for at least 8 hours as specified in § 192.505.
 - (4) After the test pressure stabilizes at the baseline pressure and within the first 2 hours of the 8-hour test interval, the hydrostatic pressure must be raised (spiked) to a minimum of the lesser of 1.5 times MAOP or 100% SMYS. This spike hydrostatic pressure test must be held for at least 15 minutes after the spike test pressure stabilizes.
- (b) Other technology or other technical evaluation process. Operators may use other technology, or another process supported by a documented engineering analysis for establishing a spike hydrostatic pressure test or equivalent. Operators must notify PHMSA 90 days in advance of the assessment or reassessment requirements of this subchapter. The notification must be made in accordance with § 192.18 and must include the following information:
 - (1) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments;
 - (2) Procedures and processes to conduct tests, examinations, assessments, perform evaluations, analyze defects, and remediate defects discovered;

- (3) Data requirements, including original design, maintenance and operating history, anomaly or flaw characterization;
- (4) Assessment techniques and acceptance criteria;
- (5) Remediation methods for assessment findings;
- (6) Spike hydrostatic pressure test monitoring and acceptance procedures, if used;
- (7) Procedures for remaining crack growth analysis and pipeline segment life analysis for the time interval for additional assessments, as required; and
- (8) Evidence of a review of all procedures and assessments by a qualified technical subject matter expert.

§ 192.507 Test Requirements for Pipelines to Operate at a Hoop Stress Less Than 30 Percent of SMYS and at or Above 100 P.S.I. (689 kPa) Gage

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage must be tested in accordance with the following:

- (a) The test procedure used must reasonably ensure discovery of leaks in the segment being tested.
- (b) If, during the test, the segment is to be stressed to 20 percent or more of SMYS and natural gas, inert gas, or air is the test medium:
 - (1) A leak test must be made at a pressure between 100 p.s.i. (689 kPa) gage and the pressure required to produce a hoop stress of 20 percent of SMYS; or
 - (2) The line must be walked to check for leaks while the hoop stress is held at approximately 20 percent of SMYS.
- (c) The pressure must be maintained at or above the test pressure for at least 1 hour.
- (d) For fabricated units and short sections of pipe, for which a post installation test is impractical, a pre-installation hydrostatic pressure test must be conducted in accordance with the requirements of this section.

§ 192.509 Test Requirements for Pipelines to Operate Below 100 P.S.I. (689 kPa) Gage

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated below 100 p.s.i.g. must be leak tested in accordance with the following:

- (a) The test procedure used must reasonably ensure discovery of leaks in the segment being tested.
- (b) Each main that is to be operated at less than 1 p.s.i. (6.9 kPa) gage must be tested to at least 10 p.s.i. (69 kPa) gage and each main to be operated at or above 1 p.s.i. (6.9 kPa) gage must be tested to at least 90 p.s.i. (621 kPa) gage.

§ 192.511 Test Requirements for Service Lines

- (a) Each segment of a service line (other than plastic) must be leak tested in accordance with this section before being placed in service. If feasible, the service line connection to the main must be included in the test; if not feasible, it must be given a leakage test at the operating pressure when placed in service.
- (b) Each segment of a service line (other than plastic) intended to be operated at pressure of less than 1 p.s.i. (6.9 kPa) gage shall be given a leak test at a pressure of 10 p.s.i. (69

kPa) gage. This test shall be conducted with a 3 inch (76 millimeters) dial gauge with a maximum scale of 30 p.s.i. (207 kPa) gage. This test may be conducted with a mercury gauge capable of testing to 10 inches (254 millimeters) of mercury.

- (c) Each segment of a service line (other than plastic) intended to be operated at a pressure of at least 1 p.s.i. (6.9 kPa) gage but not more than 40 p.s.i. (276 kPa) gage must be given a leak test at a pressure of not less than 50 p.s.i. (345 kPa) gage on a 100 p.s.i. (689 kPa) gage scale gauge.
- (d) Each segment of a service line (other than plastic) intended to be operated at pressures of more than 40 p.s.i.g. must be tested to at least 90 p.s.i.g. on 100 p.s.i.g. scale gauge, except that each segment of a steel service line stressed to 20 percent or more of SMYS must be tested in accordance with § 192.507.
- (e) The test procedure used must reasonably ensure discovery of leaks in the segment being tested.

§ 192.513 Test Requirements for Plastic Pipelines

- (a) Each segment of a plastic pipeline must be tested in accordance with this section.
- (b) The test procedure used must reasonably ensure discovery of leaks in the segment being tested.
- (c) The test pressure must be at least 150% of the maximum operating pressure or 50 p.s.i. (345 kPa) gauge, whichever is greater. However, the maximum test pressure may not be more than 2.5 times the pressure determined under § 192.121, at a temperature not less than the pipe temperature during the test.
- (d) During the test, the temperature of thermoplastic material may not be more than 100°F (38°C), or the temperature at which the material's long-term hydrostatic strength has been determined under the listed specification, whichever is greater.

§ 192.515 Environmental Protection and Safety Requirements

- (a) In conducting tests under this subpart, each operator shall ensure that every reasonable precaution is taken to protect its employees and the general public during the testing. Whenever the hoop stress of the segment of the pipeline being tested will exceed 50 percent of SMYS, the operator shall take all practicable steps to keep persons not working on the testing operation outside of the testing area until the pressure is reduced to or below the proposed maximum allowable operating pressure.
- (b) The operator shall insure that the test medium is disposed of in a manner that will minimize damage to the environment.

§ 192.517 Records: Tests

- (a) Each operator must make and retain for the useful life of the pipeline, a record of each test performed under §§ 192.505, 192.507, and 192.507. The record must contain at least the following information:
 - (1) The operator's name, the name of the operator's employee responsible for making the test and the name of any test company used.
 - (2) Test medium used.
 - (3) Test pressure.
 - (4) Test duration.

- (5) Pressure recording charts or other records of pressure readings.
 - (6) Evaluation variations, whenever significant for the particular test.
 - (7) Leaks and failures noted and their disposition.
- (b) Each operator must maintain a record of each test required by §§ 192.509, 192.511, and 192.513 for at least 5 years.

SUBPART K - UPRATING

§ 192.551 Scope

This subpart prescribes minimum requirements for increasing maximum allowable operating pressures (uprating) for pipelines.

§ 192.553 General Requirements

- (a) *Pressure increases.* Whenever the requirements of this subpart require that an increase in operating pressure be made in increments, the pressure must be increased gradually, at a rate that can be controlled, and in accordance with the following:
 - (1) At the end of each incremental increase, the pressure must be held constant while the entire segment of pipeline that is affected is checked for leaks.
 - (2) Each leak detected must be repaired before a further pressure increase is made, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous.
- (b) *Records.* Each operator who uprates a segment of pipeline shall retain for the life of the segment a record of each investigation required by this subpart, of all work performed, and of each pressure test conducted, in connection with the uprating.
- (c) *Written plan.* Each operator who uprates a segment of pipeline shall establish a written procedure that will ensure that each applicable requirement of this subpart is complied with.
- (d) *Limitation on increase in maximum allowable operating pressure.* Except as provided in § 192.555(c), a new maximum allowable operating pressure established under this subpart may not exceed the maximum that would be allowed under § 192.619 and 192.621 for a new segment of pipeline constructed of the same materials in the same location. However, when uprating a steel pipeline, if any variable necessary to determine the design pressure under the design formula (§ 192.105) is unknown, the MAOP may be increased as provided in § 192.619(a)(1).

§ 192.555 Uprating to a Pressure That Will Produce a Hoop Stress of 30 Percent or More of SMYS in Steel Pipelines

- (a) Unless the requirements of this section have been met, no person may subject any segment of a steel pipeline to an operating pressure that will produce a hoop stress of 30 percent or more of SMYS and that is above the established maximum allowable operating pressure.
- (b) Before increasing operating pressure above the previously established pressure the operator shall:
 - (1) Review the design, operating and maintenance history and previous testing of the

segment of pipeline and determine whether the proposed increase is safe and consistent with the requirements of this part; and

- (2) Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure.
- (c) After complying with paragraph (b) of this section, an operator may increase the maximum allowable operating pressure of a segment of pipeline constructed before September 12, 1970, to the highest pressure that is permitted under § 192.619, using as test pressure the highest pressure to which the segment of pipeline was previously subjected (either in a strength test or in actual operation).
- (d) After complying with paragraph (b) of this section, an operator that does not qualify under paragraph (c) of this section may increase the previously established maximum allowable operating pressure if at least one of the following requirements is met:
 - (1) The segment of pipeline is successfully tested in accordance with the requirements of this part for a new line of the same material in the same location.
 - (2) An increased maximum allowable operating pressure may be established for a segment of pipeline in a Class 1 location if the line has not previously been tested, and if:
 - (i) It is impractical to test it in accordance with the requirements of this part;
 - (ii) The new maximum operating pressure does not exceed 80 percent of that allowed for a new line of the same design in the same location; and
 - (iii) The operator determines that the new maximum allowable operating pressure is consistent with the condition of the segment of pipeline and the design requirements of this part.
- (e) Where a segment of pipeline is uprated in accordance with paragraph (c) or (d)(2) of this section, the increase in pressure must be made in increments that are equal to:
 - (1) 10 percent of the pressure before the uprating; or
 - (2) 25 percent of the total pressure increase, whichever produces the fewer number of increments.

§ 192.557 Uprating Steel Pipelines to a Pressure That Will Produce a Hoop Stress Less Than 30 Percent of SMYS: Plastic, Cast Iron, and Ductile Iron Pipelines

- (a) Unless the requirements of this section have been met, no person may subject:
 - (1) A segment of steel pipeline to an operating pressure that will produce a hoop stress less than 30 percent of SMYS and that is above the previously established maximum allowable operating pressure; or
 - (2) A plastic, cast iron, or ductile iron pipeline segment to an operating pressure that is above the previously established maximum allowable operating pressure.
- (b) Before increasing operating pressure above the previously established maximum allowable operating pressure, the operator shall:
 - (1) Review the design, operating, and maintenance history of the segment of pipeline;
 - (2) Make a leakage survey (if it has been more than 1 year since the last survey) and repair any leaks that are found, except that a leak determined not to be potentially hazardous need not be repaired if it is monitored during the pressure increase and

- it does not become potentially hazardous;
- (3) Make any repairs, replacements or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure;
 - (4) Reinforce or anchor offsets, bends and dead ends in pipe joined by compression couplings or bell and spigot joints to prevent failure of the pipe joint, if the offset, bend or dead end is exposed in an excavation;
 - (5) Isolate the segment of pipeline in which the pressure is to be increased from any adjacent segment that will continue to be operated at a lower pressure; and
 - (6) If the pressure in mains or service lines, or both, is to be higher than the pressure delivered to the customer, install a service regulator on each service line and test each regulator to determine that it is functioning. Pressure may be increased as necessary to test each regulator, after a regulator has been installed on each pipeline subject to the increased pressure.
- (c) After complying with paragraph (b) of this section, the increase in maximum allowable operating pressure must be made in increments that are equal to 10 p.s.i. (69 kPa) gage or 25 percent of the total pressure increase, whichever produces the fewer number of increments. Whenever the requirements of paragraph (b)(6) of this section apply, there must be at least two approximately equal incremental increases.
- (d) If records for cast iron or ductile iron pipeline facilities are not complete enough to determine stresses produced by internal pressure, trench loading, rolling loads, beam stresses, and other bending loads, in evaluating the level of safety of the pipeline when operating at the proposed increased pressure, the following procedures must be followed:
- (1) In estimating the stresses, if the original laying conditions cannot be ascertained, the operator shall assume that cast iron pipe was supported on blocks with tamped backfill and that ductile iron pipe was laid without blocks with tamped backfill.
 - (2) Unless the actual maximum cover depth is known, the operator shall measure the actual cover in at least three places where the cover is most likely to be greatest and shall use the greatest cover measured.
 - (3) Unless the actual nominal wall thickness is known, the operator shall determine the wall thickness by cutting and measuring coupons from at least three separate pipe lengths. The coupons must be cut from pipe lengths in areas where the cover depth is most likely to be the greatest. The average of all measurements taken must be increased by the allowance indicated in the following table:

Pipe Size Inches (millimeters)	ALLOWANCE Inches (millimeters)		
	Cast Iron Pipe		
	Cast Iron Pipe		Ductile iron pipe
Pit Cast Pipe	Centrifugally Cast Pipe		
3-8 (76-203)	0.075(1.9)	0.065(1.6)	0.065(1.6)
10-12 (254 to 305)	0.08(2.03)	0.07(1.7)	0.07(1.7)
14-24 (356 to 610)	0.08(2.03)	0.08(2.0)	0.075(1.9)
30-42 (762 to 1067)	0.09(2.29)	0.09(2.2)	0.075(1.9)

48 (1219)	0.09(2.29)	0.09(2.2)	0.08(2.0)
54-60 (1372 to 1524)	0.09(2.29)	-----	-----

- (4) For cast iron pipe, unless the pipe manufacturing process is known, the operator shall assume that the pipe is pit cast pipe with a bursting tensile strength of 11,000 p.s.i. (76 MPa) gage and a modulus of rupture of 31,000 p.s.i. (214 MPa) gage.

SUBPART L - OPERATIONS

§ 192.601 Scope

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

§ 192.603 General Provisions

- (a) No person may operate a segment of pipeline unless it is operated in accordance with this subpart.
- (b) Each operator shall keep records necessary to administer the procedures established under § 192.605.
- (c) The Administrator or the State Agency that has submitted a current certification under the pipeline safety laws (49 U.S.C. 60101 *et seq.*) with respect to the pipeline facility governed by an operator's plans and procedures may, after notice and opportunity for hearing as provided in 49 CFR 190.206 or the relevant State procedures, require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety.

§ 192.605 Procedural Manual for Operations, Maintenance, and Emergencies

- (a) *General.* Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling

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

- (b) *Maintenance and normal operations.* The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations:
- (1) Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this subpart and subpart M of this part.
 - (2) Controlling corrosion in accordance with the operations and maintenance requirements of subpart I of this part.
 - (3) Making construction records, maps, and operating history available to appropriate personnel.
 - (4) Gathering of data needed for reporting incidents under Part 191 in a timely and effective manner.
 - (5) Starting up and shutting down any part of the pipeline in a manner designed to assure operation within the MAOP limits prescribed by this part, plus the build-up allowed for operation of pressure-limiting and control devices.
 - (6) Maintaining compressor stations, including provisions for isolating units or sections of pipe and for purging before returning to service.
 - (7) Starting, operating and shutting down gas compressor units.
 - (8) Periodically reviewing the work done by operator personnel to determine the effectiveness, and adequacy of the procedures used in normal operation and maintenance and modifying the procedures when deficiencies are found.
 - (9) Taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas and making available when needed at the excavation emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.
 - (10) Systematic and routine testing and inspection of pipe-type or bottle-type holders including:
 - (i) Provision for detecting external corrosion before the strength of the container has been impaired;
 - (ii) Periodic sampling and testing of gas in storage to determine the dew point of vapors contained in the stored gas which, if condensed, might cause internal corrosion or interfere with the safe operation of the storage plant; and
 - (iii) Periodic inspection and testing of pressure limiting equipment to determine that it is in safe operating condition and has adequate capacity.
 - (11) Responding promptly to a report of a gas odor inside or near a building, unless the operator's emergency procedures under § 192.615(a)(3) specifically apply to these reports.
 - (12) Implementing the applicable control room management procedures required by §

192.631.

- (c) *Abnormal operations.* For transmission lines, the manual required by subparagraph (a) of this paragraph must include procedures for the following to provide safety when operating design limits have been exceeded:
- (1) Responding to, investigating, and correcting the cause of:
 - (i) Unintended closure of valves or shutdowns;
 - (ii) Increase or decrease in pressure or flow rate outside normal operating limits;
 - (iii) Loss of communications;
 - (iv) Operation of any safety device; and
 - (v) Any other foreseeable malfunction of a component, deviation from normal operation, or personnel error which may result in a hazard to persons or property.
 - (2) Checking variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation.
 - (3) Notifying responsible operator personnel when notice of an abnormal operation is received.
 - (4) Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.
 - (5) The requirements of this paragraph do not apply to natural gas distribution operators that are operating transmission lines in connection with their distribution system.
- (d) *Safety-related condition reports.* The manual required by subparagraph (a) of this paragraph must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of § 191.23.
- (e) *Surveillance, emergency response, and accident investigation.* The procedures required by §§ 192.613(a), 192.615, and 192.617 must be included in the manual required by paragraph (a) of this section.

§ 192.607 Verification Of Pipeline Material Properties And Attributes: Onshore Steel Transmission Pipelines.

- (a) *Applicability.* Wherever required by this part, operators of onshore steel transmission pipelines must document and verify material properties and attributes in accordance with this section.
- (b) *Documentation of material properties and attributes.* Records established under this section documenting physical pipeline characteristics and attributes, including diameter, wall thickness, seam type, and grade (e.g., yield strength, ultimate tensile strength, or pressure rating for valves and flanges, etc.), must be maintained for the life of the pipeline and be traceable, verifiable, and complete. Charpy v-notch toughness values established under this section needed to meet the requirements of the ECA method at § 192.624(c)(3) or the fracture mechanics requirements at § 192.712 must be maintained for the life of the

pipeline.

- (c) *Verification of material properties and attributes.* If an operator does not have traceable, verifiable, and complete records required by paragraph (b) of this section, the operator must develop and implement procedures for conducting nondestructive or destructive tests, examinations, and assessments in order to verify the material properties of aboveground line pipe and components, and of buried line pipe and components when excavations occur at the following opportunities: Anomaly direct examinations, *in situ* evaluations, repairs, remediations, maintenance, and excavations that are associated with replacements or relocations of pipeline segments that are removed from service. The procedures must also provide for the following:
- (1) For nondestructive tests, at each test location, material properties for minimum yield strength and ultimate tensile strength must be determined at a minimum of 5 places in at least 2 circumferential quadrants of the pipe for a minimum total of 10 test readings at each pipe cylinder location.
 - (2) For destructive tests, at each test location, a set of material properties tests for minimum yield strength and ultimate tensile strength must be conducted on each test pipe cylinder removed from each location, in accordance with API Specification 5L.
 - (3) Tests, examinations, and assessments must be appropriate for verifying the necessary material properties and attributes.
 - (4) If toughness properties are not documented, the procedures must include accepted industry methods for verifying pipe material toughness.
 - (5) Verification of material properties and attributes for non-line pipe components must comply with paragraph (f) of this section.
- (d) *Special requirements for nondestructive methods.* Procedures developed in accordance with paragraph (c) of this section for verification of material properties and attributes using nondestructive methods must:
- (1) Use methods, tools, procedures, and techniques that have been validated by a subject matter expert based on comparison with destructive test results on material of comparable grade and vintage;
 - (2) Conservatively account for measurement inaccuracy and uncertainty using reliable engineering tests and analyses; and
 - (3) Use test equipment that has been properly calibrated for comparable test materials prior to usage.
- (e) *Sampling multiple segments of pipe.* To verify material properties and attributes for a population of multiple, comparable segments of pipe without traceable, verifiable, and complete records, an operator may use a sampling program in accordance with the following requirements:
- (1) The operator must define separate populations of similar segments of pipe for each combination of the following material properties and attributes: Nominal wall thicknesses, grade, manufacturing process, pipe manufacturing dates, and construction dates. If the dates between the manufacture or construction of the pipeline segments exceeds 2 years, those segments cannot be considered as the same vintage for the purpose of defining a population under this section. The total population mileage is the cumulative mileage of pipeline segments in the

- population. The pipeline segments need not be continuous.
- (2) For each population defined according to paragraph (e)(1) of this section, the operator must determine material properties at all excavations that expose the pipe associated with anomaly direct examinations, *in situ* evaluations, repairs, remediations, or maintenance, except for pipeline segments exposed during excavation activities pursuant to § 192.614, until completion of the lesser of the following:
 - (i) One excavation per mile rounded up to the nearest whole number; or
 - (ii) 150 excavations if the population is more than 150 miles.
 - (3) Prior tests conducted for a single excavation according to the requirements of paragraph (c) of this section may be counted as one sample under the sampling requirements of this paragraph (e).
 - (4) If the test results identify line pipe with properties that are not consistent with available information or existing expectations or assumed properties used for operations and maintenance in the past, the operator must establish an expanded sampling program. The expanded sampling program must use valid statistical bases designed to achieve at least a 95% confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. Operators must notify PHMSA in advance of using an expanded sampling approach in accordance with § 192.18.
 - (5) An operator may use an alternative statistical sampling approach that differs from the requirements specified in paragraph (e)(2) of this section. The alternative sampling program must use valid statistical bases designed to achieve at least a 95% confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. Operators must notify PHMSA in advance of using an alternative sampling approach in accordance with § 192.18.
- (f) **Components.** For mainline pipeline components other than line pipe, an operator must develop and implement procedures in accordance with paragraph (c) of this section for establishing and documenting the ANSI rating or pressure rating (in accordance with ASME/ANSI B16.5 (incorporated by reference, see § 192.7)),
- (1) Operators are not required to test for the chemical and mechanical properties of components in compressor stations, meter stations, regulator stations, separators, river crossing headers, mainline valve assemblies, valve operator piping, or cross-connections with isolation valves from the mainline pipeline.
 - (2) Verification of material properties is required for non-line pipe components, including valves, flanges, fittings, fabricated assemblies, and other pressure retaining components and appurtenances that are:
 - (i) Larger than 2 inches in nominal outside diameter,
 - (ii) Material grades of 42,000 psi (Grade X-42) or greater, or

- (iii) Appurtenances of any size that are directly installed on the pipeline and cannot be isolated from mainline pipeline pressures.
- (3) Procedures for establishing material properties of non-line pipe components must be based on the documented manufacturing specification for the components. If specifications are not known, usage of manufacturer's stamped, marked, or tagged material pressure ratings and material type may be used to establish pressure rating. Operators must document the method used to determine the pressure rating and the findings of that determination.
- (g) **Uprating.** The material properties determined from the destructive or nondestructive tests required by this section cannot be used to raise the grade or specification of the material, unless the original grade or specification is unknown and MAOP is based on an assumed yield strength of 24,000 psi in accordance with § 192.107(b)(2).

§ 192.609 Change in Class Location: Required Study

Whenever an increase in population density indicates a change in class location for a segment of an existing steel pipeline operating at hoop stress that is more than 40 percent of SMYS, or indicates that the hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location, the operator shall immediately make a study to determine:

- (a) The present class location for the segment involved;
- (b) The design, construction, and testing procedures followed in the original construction, and a comparison of these procedures with those required for the present class location by the applicable provisions of this part;
- (c) The physical condition of the segment to the extent it can be ascertained from available records;
- (d) The operating and maintenance history of the segment;
- (e) The maximum actual operating pressure and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved; and
- (f) The actual area affected by the population density increase, and physical barriers or other factors which may limit further expansion of the more densely populated area.

§ 192.610 Change in class location: Change in valve spacing.

- (a) If a class location change on a transmission pipeline occurs after October 5, 2022, and results in pipe replacement, of 2 or more miles, in the aggregate, within any 5 contiguous miles within a 24-month period, to meet the maximum allowable operating pressure (MAOP) requirements in § 192.611, § 192.619, or § 192.620, then the requirements in §§ 192.179, 192.634, and 192.636, as applicable, apply to the new class location, and the operator must install valves, including rupture-mitigation valves (RMV) or alternative equivalent technologies, as necessary, to comply with those sections. Such valves must be installed within 24 months of the class location change in accordance with the timing requirement in § 192.611(d) for compliance after a class location change.
- (b) If a class location change on a gas transmission pipeline occurs after October 5, 2022, and results in pipe replacement of less than 2 miles within 5 contiguous miles during a 24-month period, to meet the MAOP requirements in § 192.611, § 192.619, or § 192.620,

then within 24 months of the class location change, in accordance with § 192.611(d), the operator must either:

(1) Comply with the valve spacing requirements of § 192.179(a) for the replaced pipeline segment; or

(2) Install or use existing RMVs or alternative equivalent technologies so that the entirety of the replaced pipeline segments are between at least two RMVs or alternative equivalent technologies. The distance between RMVs and alternative equivalent technologies for the replaced segment must not exceed 20 miles. The RMVs and alternative equivalent technologies must comply with the applicable requirements of § 192.636.

(c) The provisions of paragraph (b) of this section do not apply to pipeline replacements that amount to less than 1,000 feet within any one contiguous mile during any 24-month period.

§ 192.611 Change in Class Location: Confirmation or Revision of Maximum Allowable Operating Pressure

(a) If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised according to one of the following requirements:

(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 the SMYS in Class 3 locations.

(2) The maximum allowable operating pressure of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by this part for new segments of pipelines in the existing class location.

(3) The segment involved must be tested in accordance with the applicable requirements of Subpart J of this part, and its maximum allowable operating pressure must then be established according to the following criteria:

(i) The maximum allowable operating pressure after the requalification test is 0.8 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.
- (b) The maximum allowable operating pressure confirmed or revised in accordance with this section, may not exceed the maximum allowable operating pressure established before the confirmation or revision.
- (c) Confirmation or revision of the maximum allowable operating pressure of a segment of pipeline in accordance with this section does not preclude the application of §§ 192.553 and 192.555.
- (d) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under § 192.609 must be completed within 24 months of the change in class location. Pressure reduction under paragraph (a) (1) or (2) of this section within the 24- month period does not preclude establishing a maximum allowable operating pressure under paragraph (a)(3) of this section at a later date.

§ 192.613 Continuing Surveillance

- (a) Each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.
- (b) If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved, or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with §§ 192.619(a) and (b).
- (c) Following an extreme weather event or natural disaster that has the likelihood of damage to pipeline facilities by the scouring or movement of the soil surrounding the pipeline or movement of the pipeline, such as a named tropical storm or hurricane; a flood that exceeds the river, shoreline, or creek high-water banks in the area of the pipeline; a landslide in the area of the pipeline; or an earthquake in the area of the pipeline, an operator must inspect all potentially affected onshore transmission pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline.
 - (1) An operator must assess the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline in determining the appropriate method for performing the initial inspection to determine the extent of any damage and the need for the additional assessments required under this paragraph (c)(1).
 - (2) An operator must commence the inspection required by paragraph (c) of this section within 72 hours after the point in time when the operator reasonably determines that the affected area can be safely accessed by personnel and equipment, and the personnel and equipment required to perform the inspection as determined by paragraph (c)(1) of this section are available. If an operator is unable to commence the inspection due to the unavailability of personnel or

equipment, the operator must notify the appropriate PHMSA Region Director and the Pipeline Safety Office Program Manager electronically via email as soon as practicable.

- (3) An operator must take prompt and appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained as a result of performing the inspection required by paragraph (c) of this section. Such actions might include, but are not limited to:
- (i) Reducing the operating pressure or shutting down the pipeline;
 - (ii) Modifying, repairing, or replacing any damaged pipeline facilities;
 - (iii) Preventing, mitigating, or eliminating any unsafe conditions in the pipeline right-of-way;
 - (iv) Performing additional patrols, surveys, tests, or inspections;
 - (v) Implementing emergency response activities with Federal, State, or local personnel; or
 - (vi) Notifying affected communities of the steps that can be taken to ensure public safety.

§ 192.614 Damage Prevention Program

- (a) Except as provided in paragraph (d) of this section, each operator of a buried pipeline must carry out, in accordance with this section, a written program to prevent damage to that pipeline from excavation activities. For the purpose of this section, the term "excavation activities" includes to dig, compress, or remove earth, rock, or other materials in or on the ground by use of mechanized equipment, tools manipulated only by human or animal power, or blasting, including without limitation augering, boring, backfilling, drilling, grading, pile-driving, plowing in, pulling in, trenching, tunneling, and plowing.
- (b) An operator may comply with any of the requirements of paragraph (c) of this section through participation in a public service program, such as a one-call system, but such participation does not relieve the operator of responsibility for compliance with this section. However, an operator must perform the duties of paragraph (c)(3) of this section through participation in a one-call system, if that one-call system is a qualified one-call system. In areas that are covered by more than one qualified one-call system, an operator need only join one of the qualified one-call systems if there is a central telephone number for excavators to call for excavation activities, or if the one-call systems in those areas communicate with one another. An operator's pipeline system must be covered by a qualified one-call system where there is one in place. For the purpose of this section, a one-call system is considered a "qualified one-call system" if it meets the requirements of section (b)(1) or (b)(2) of this section.
- (1) The state has adopted a one-call damage prevention program under 49 CFR §198.37; or
 - (2) The one-call system:
 - (i) Is operated in accordance with 49 CFR §198.39;
 - (ii) Provides a pipeline operator an opportunity similar to a voluntary participant to have a part in management responsibilities; and
 - (iii) Assesses a participating pipeline operator a fee that is proportionate to the

costs of the one-call system's coverage of the operator's pipeline.

- (c) The damage prevention program required by paragraph (a) of this section must, at a minimum:
- (1) Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.
 - (2) Provides for notification of the public in the vicinity of the pipeline and actual notification of the persons identified in paragraph (c)(1) of this section of the following as often as needed to make them aware of the damage prevention program:
 - (i) The program's existence and purpose; and
 - (ii) How to learn the location of underground pipelines before excavation activities are begun.
 - (3) Provide a means of receiving and recording notification of planned excavation activities.
 - (4) If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.
 - (5) Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.
 - (6) Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:
 - (i) The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline; and
 - (ii) In the case of blasting, any inspection must include leakage surveys.
- (d) Pipelines operated by persons other than municipalities (including operators of master meters) whose primary activity does not include the transportation of gas need not comply with the following:
- (1) The requirement of paragraph (a) of this section that the damage prevention program be written; and
 - (2) The requirements of paragraphs (c)(1) and (c)(2) of this section.

§ 192.615 Emergency Plans

- (a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:
- (1) Receiving, identifying, and classifying notices of events which require immediate response by the operator.
 - (2) ~~Establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials. Establishing and maintaining adequate means of communication with the appropriate public safety answering point (i.e., 9-1-1 emergency call center), where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, and fire, police, and other public officials. Operators may establish liaison with the appropriate local emergency coordinating agencies, such as 9-1-1 emergency call centers or county emergency managers, in lieu~~

of communicating individually with each fire, police, or other public entity. An operator must determine the responsibilities, resources, jurisdictional area(s), and emergency contact telephone number(s) for both local and out-of-area calls of each Federal, State, and local government organization that may respond to a pipeline emergency, and inform such officials about the operator's ability to respond to a pipeline emergency and the means of communication during emergencies.

- (3) Prompt and effective response to a notice of each type of emergency, including the following:
 - (i) Gas detected inside or near a building.
 - (ii) Fire located near or directly involving a pipeline facility.
 - (iii) Explosion occurring near or directly involving a pipeline facility.
 - (iv) Natural disaster.
- (4) The availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency.
- (5) Actions directed toward protecting people first and then property.
- (6) ~~Emergency shutdown and pressure reduction in any section of the operator's pipeline system necessary to minimize hazards to life or property. Making safe any actual or potential hazard to life or property. Taking necessary actions, including but not limited to, emergency shutdown, valve shut-off, or pressure reduction, in any section of the operator's pipeline system, to minimize hazards of released gas to life, property, or the environment.~~
- (7) ~~Safely restoring any service outage. Making safe any actual or potential hazard to life or property.~~
- (8) ~~Beginning action under § 192.617, if applicable, as soon after the end of the emergency as possible. Notifying the appropriate public safety answering point (i.e., 9-1-1 emergency call center) where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, and fire, police, and other public officials, of gas pipeline emergencies to coordinate and share information to determine the location of the emergency, including both planned responses and actual responses during an emergency. The operator must immediately and directly notify the appropriate public safety answering point or other coordinating agency for the communities and jurisdictions in which the pipeline is located after receiving a notification of potential rupture, as defined in § 192.3, to coordinate and share information to determine the location of any release, regardless of whether the segment is subject to the requirements of § 192.179, § 192.634, or § 192.636.~~
- (9) Safely restoring any service outage.
- (10) Beginning action under § 192.617, if applicable, as soon after the end of the emergency as possible.
- (11) ~~Actions required to be taken by a controller during an emergency in accordance with § 192.631. Furnish its supervisors who are responsible for emergency action a copy of that portion of the latest edition of the emergency procedures established under paragraph (a) of this section as necessary for compliance with those procedures. Actions required to be taken by a controller during an emergency in accordance with the operator's emergency plans and requirements set forth in §§ 192.631, 192.634, and 192.636.~~

- (12) Each operator must develop written rupture identification procedures to evaluate and identify whether a notification of potential rupture, as defined in § 192.3, is an actual rupture event or a non-rupture event. These procedures must, at a minimum, specify the sources of information, operational factors, and other criteria that operator personnel use to evaluate a notification of potential rupture and identify an actual rupture. For operators installing valves in accordance with § 192.179(e), § 192.179(f), or that are subject to the requirements in § 192.634, those procedures must provide for rupture identification as soon as practicable.
- (13) Train the appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and verify that the training is effective.
- (14) Review employee activities to determine whether the procedures were effectively followed in each emergency.
- (b) Each operator shall ~~establish and maintain liaison with appropriate fire, police, and other public officials to:~~
- ~~(1) Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency;~~
- ~~(2)(1) Acquaint the officials with the operator's ability in responding to a gas pipeline emergency;~~
- ~~(3)(1) Identify the types of gas pipeline emergencies of which the operator notifies the officials; and~~
- ~~(4)(1) Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property.~~
- (1) Furnish its supervisors who are responsible for emergency action a copy of that portion of the latest edition of the emergency procedures established under paragraph (a) of this section as necessary for compliance with those procedures.
- (2) Train the appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and verify that the training is effective.
- (3) Review employee activities to determine whether the procedures were effectively followed in each emergency.
- (c) ~~Each operator shall maintain a current map of the entire gas system or sectional maps of large systems. These maps will be of sufficient detail to approximate the location of mains and transmission lines. Each operator must establish and maintain liaison with the appropriate public safety answering point (i.e., 9-1-1 emergency call center) where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, as well as fire, police, and other public officials, to:~~
- ~~(1) Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency;~~
- ~~(2) Acquaint the officials with the operator's ability in responding to a gas pipeline emergency;~~
- ~~(3) Identify the types of gas pipeline emergencies of which the operator notifies the~~

officials; and

(4) Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property.

- (d)(1) Each operator shall identify all key valves which may be necessary for the safe operation of the system. The location of these valves shall be designated on appropriate records, drawings, or maps.
- (2) As used in subdivision (e)(1) of this section, "key valves" means shut off valves in a distribution system or transmission line which may be necessary to isolate segments of a system or line for emergency purposes.

§ 192.616 Public Awareness

- (a) Except for an operator of a master meter or petroleum gas system covered under paragraph (j) of this section, each pipeline operator must develop and implement a written continuing public education program that follows the guidance provided in the American Petroleum (API) Recommended Practice (RP) 1162 (incorporated by reference, see § 192.7).
- (b) The operator's program must follow the general program recommendations of API RP 1162 and assess the unique attributes and characteristics of the operator's pipeline and facilities.
- (c) The operator must follow the general program recommendations, including baseline and supplemental requirements of API RP 1162, unless the operator provides justification in its program or procedural manual as to why compliance with all or certain provisions of the recommended practice is not practicable and not necessary for safety.
- (d) The operator's program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on:
- (1) Use of a one-call notification system prior to excavation and other damage prevention activities;
 - (2) Possible hazards associated with unintended releases from a gas pipeline facility;
 - (3) Physical indications that such a release may have occurred;
 - (4) Steps that should be taken for public safety in the event of a gas pipeline release; and
 - (5) Procedures for reporting such an event.
- (e) The program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations.
- (f) The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports gas.
- (g) The program must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area.
- (h) Operators in existence on June 20, 2005, must have completed their written programs no later than June 20, 2006. The operator of a master meter or petroleum gas system covered

under paragraph (j) of this section must complete development of its written procedure by June 13, 2008. Upon request, operators must submit their completed programs to PHMSA or, in the case of an intrastate pipeline facility operator, the appropriate State agency.

- (i) The operator's program documentation and evaluation results must be available for periodic review by appropriate regulatory agencies.
- (j) Unless the operator transports gas as a primary activity, the operator of a master meter or petroleum gas system is not required to develop a public awareness program as prescribed in paragraphs (a) through (g) of this section. Instead, the operator must develop and implement a written procedure to provide its customers public awareness messages twice annually. If the master meter or petroleum gas system is located on property the operator does not control, the operator must provide similar messages twice annually to persons controlling the property. The public awareness message must include:
 - (1) A description of the purpose and reliability of the pipeline;
 - (2) An overview of the hazards of the pipeline and prevention measures used;
 - (3) Information about damage prevention;
 - (4) How to recognize and respond to a leak; and
 - (5) How to get additional information.

§ 192.617 Investigation of Failures

~~Each operator shall establish procedures for analyzing accidents and failures, including the selection of samples of the failed facility or equipment for laboratory examination, where appropriate, for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence.~~

- (a) Post-failure and incident procedures. Each operator must establish and follow procedures for investigating and analyzing failures and incidents as defined in § 191.3, including sending the failed pipe, component, or equipment for laboratory testing or examination, where appropriate, for the purpose of determining the causes and contributing factor(s) of the failure or incident and minimizing the possibility of a recurrence.
- (b) Post-failure and incident lessons learned. Each operator of a transmission or distribution pipeline must develop, implement, and incorporate lessons learned from a post-failure or incident review into its written procedures, including personnel training and qualification programs; and design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications.
- (c) Analysis of rupture and valve shutoffs. If an incident on an onshore gas transmission pipeline or a Type A gathering pipeline involves the closure of a rupture-mitigation valve (RMV), as defined at § 192.3, or the closure of alternative equivalent technology, the operator of the pipeline must also conduct a post-incident analysis of all of the factors that may have impacted the release volume and the consequences of the incident and identify and implement operations and maintenance measures to prevent or minimize the consequences of a future incident. The requirements of this paragraph (c) are not applicable to gas distribution or Types B and C gas gathering pipelines. The analysis must include all relevant factors impacting the release volume and consequences, including, but not limited to, the following:

- (1) Detection, identification, operational response, system shut-off, and emergency response communications, based on the type and volume of the incident;
 - (2) Appropriateness and effectiveness of procedures and pipeline systems, including supervisory control and data acquisition (SCADA), communications, valve shut-off, and operator personnel;
 - (3) Actual response time from identifying a rupture following a notification of potential rupture, as defined at § 192.3, to initiation of mitigative actions and isolation of the pipeline segment, and the appropriateness and effectiveness of the mitigative actions taken;
 - (4) Location and timeliness of actuation of RMVs or alternative equivalent technologies; and
 - (5) All other factors the operator deems appropriate.
- (d) *Rupture post-failure and incident summary.* If a failure or incident on an onshore gas transmission pipeline or ~~Type A gathering pipeline~~ involves the identification of a rupture following a notification of potential rupture, or the closure of an RMV (as those terms are defined at § 192.3), or the closure of an alternative equivalent technology, the operator of the pipeline must complete a summary of the post-failure or incident review required by paragraph (c) of this section within 90 days of the incident, and while the investigation is pending, conduct quarterly status reviews until the investigation is complete and a final post-incident summary is prepared. The final post-failure or incident summary, and all other reviews and analyses produced under the requirements of this section, must be reviewed, dated, and signed by the operator's appropriate senior executive officer. The final post-failure or incident summary, all investigation and analysis documents used to prepare it, and records of lessons learned must be kept for the useful life of the pipeline. The requirements of this paragraph (d) are not applicable to gas distribution or ~~Types B and C~~ gas gathering pipelines.

§ 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 (MAOP) determined under paragraph (c), (d), or (e) of this section, or the lowest of the following:
 - (1) The design pressure of the weakest element in the segment, determined in accordance with Subparts C and D of this part. However, for steel pipe in pipelines being converted under § 192.14 or uprated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§ 192.105) is unknown, one of the following pressures is to be used as design pressure:
 - (i) Eighty percent of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8 (incorporated by reference, see § 192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or
 - (ii) If the pipe is 12 3/4 in. (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).

- (2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:
- (i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.
 - (ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the Table 1 to paragraph (a)(2)(ii):

Table 1 to Paragraph (a)(2)(ii)

Class location	Installed before (Nov. 12, 1970)	Factors, ^{1, 2} segment -		
		Installed after (Nov. 11, 1970) and before July 1, 2020	Installed on or after July 1, 2020	Converted under § 192.14
1	1.1	1.1	1.25	1.25
2	1.25	1.25	1.25	1.25
3	1.4	1.5	1.5	1.5
4	1.4	1.5	1.5	1.5

- (3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	Pressure Date	Test Date
(i) Onshore regulated gathering pipeline (Type A or Type B under § 192.9(d)) that first became subject to this part (other than § 192.612) after April 13, 2006	March 15, 2006, or date pipeline becomes subject to this part, whichever is later	5 years preceding applicable date in second column.

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

² For a component with a design pressure established in accordance with § 192.153(a) or (b) installed after July 14, 2004, the factor is 1.3.

(ii) Onshore regulated gathering pipeline (Type C under § 192.9(d) that first became subject to this part (other than § 192.612) on or after May 16, 2022	May 16, 2023, or date pipeline becomes subject to this part, whichever is later	5 years preceding applicable date in second column.
(iii) Onshore transmission pipeline that was a gathering pipeline not subject to this part before March 15, 2006	March 15, 2006, or date pipeline becomes subject to this part, whichever is later	5 years preceding applicable date in second column.
(iv) Offshore gathering pipelines	July 1, 1976	July 1, 1971
(v) All other pipelines	July 1, 1970	July 1, 1965

- (4) The pressure determined by the operator to be the maximum safe pressure after considering and accounting for records of material properties, including material properties verified in accordance with §192.607, if applicable, and the history of the pipeline segment, including known corrosion and the actual operating pressure.
- (b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with § 192.195.
- (c) The requirements on pressure restrictions in this section do not apply in the following instances:
- (1) An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section.

An operator must still comply with § 192.611.

- (2) For any Type C gas gathering pipeline under § 192.9 existing on or before May 16, 2022, that was not previously subject to this part and the operator cannot determine the actual operating pressure of the pipeline for the 5 years preceding May 16, 2023, the operator may establish MAOP using other criteria based on a combination of operating conditions, other tests, and design with approval from PHMSA and the Pipeline Safety Office. The operator must notify PHMSA and the Pipeline Safety Office in accordance with § 192.18. The notifications must include the following information:
- (i) The proposed MAOP of the pipeline;
 - (ii) Description of pipeline segment for which alternate methods are used to establish MAOP, including diameter, wall thickness, pipe grade, seam type, location, endpoints, other pertinent material properties, and age;
 - (iii) Pipeline operating data, including operating history and maintenance history;
 - (iv) Description of methods being used to establish MAOP;
 - (v) Technical justification for use of the methods chosen to establish MAOP; and
 - (vi) Evidence of review and acceptance of the justification by a qualified technical subject matter expert.
- (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).
- (e) Notwithstanding the requirements in paragraphs (a) through (d) of this section, operators of onshore steel transmission pipelines that meet the criteria specified in §192.624(a) must establish and document the maximum allowable operating pressure in accordance with §192.624.
- (f) Operators of onshore steel transmission pipelines must make and retain records necessary to establish and document the MAOP of each pipeline segment in accordance with paragraphs (a) through (e) of this section as follows:
- (1) Operators of pipelines in operation as of July 1, 2020 must retain any existing records establishing MAOP for the life of the pipeline;
 - (2) Operators of pipelines in operation as of July 1, 2020 that do not have records establishing MAOP and are required to reconfirm MAOP in accordance with §192.624, must retain the records reconfirming MAOP for the life of the pipeline; and
 - (3) Operators of pipelines placed in operation after July 1, 2020 must make and retain records establishing MAOP for the life of the pipeline.
- (g) The maximum allowable operating pressure shall be designated following the above procedures and posted on system maps, drawings, regulator stations or other appropriate records.

§ 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	1.50 ³
3	1.50

- (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

³ For Class 2 alternative maximum allowable operating pressure segments installed prior to December 22, 2008 the alternative test factor is 1.25.

§ 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) *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) For pipelines already in service, notify each PHMSA pipeline safety regional office where the pipeline is in service of the intention to use the alternative pressure at least 180 days before operating at the alternative MAOP. For new pipelines, notify the PHMSA pipeline safety regional office of planned alternative MAOP design and operation at least 60 days prior to the earliest start date of either pipe manufacturing or construction activities. An operator must also notify a state pipeline safety authority when the pipeline is located in a state where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that state.
 - (2) Certify, by signature of a senior executive officer of the company, as follows:
 - (i) The pipeline segment meets the conditions described in paragraph (b) of this section; and
 - (ii) The operating and maintenance procedures include the additional operating and maintenance requirements of paragraph (d) of this section; and
 - (iii) The review and any needed program upgrade of the damage prevention program required by paragraph (d)(4)(v) of this section has been completed.
 - (3) Send a copy of the certification required by paragraph (c)(2) of this section to each PHMSA pipeline safety regional office where the pipeline is in service 30 days prior to operating at the alternative MAOP. An operator must also send a copy to a state pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.
 - (4) For each pipeline segment, do one of the following:

- (i) Perform a strength test as described in 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 location can be upgraded one class due to class changes per § 192.611(a). All class location changes from Class 1 to Class 2 and from Class 2 to Class 3 must have all anomalies evaluated and remediated per: The “original pipeline class grade” § 192.620(d)(11) anomaly repair requirements; and all anomalies with a wall loss equal to or greater than 40 percent must be excavated and remediated. Pipelines in Class 4 may not operate at an alternative MAOP.
- (d) *What additional operation and maintenance requirements apply to operation at the alternative maximum allowable operating pressure?* In addition to compliance with other applicable safety standards in this part, if an operator establishes a maximum allowable operating pressure for a pipeline segment under paragraph (a) of this section, an operator must comply with the additional operation and maintenance requirements as follows:

To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:	Take the following additional step:
(1) Identifying and evaluating threats	Develop a threat matrix consistent with § 192.917 to do the following: (i) Identify and compare the increased risk of operating the pipeline at the increased stress level under this section with conventional operation; and
	(ii) Describe and implement procedures used to mitigate the risk.

(2) Notifying the public	(i) Recalculate the potential impact circle as defined in § 192.903 to reflect use of the alternative maximum operating pressure calculated under paragraph (a) of this section and pipeline operating conditions; and
	(ii) In implementing the public education program required under § 192.616, perform the following:
	(A) Include persons occupying property within 220 yards of the centerline and within the potential impact circle within the targeted audience; and
	(B) Include information about the integrity management activities performed under this section within the message provided to the audience.
(3) Responding to an emergency in an area defined as a high consequence area in § 192.903	(i) Ensure that the identification of high consequence areas reflects the larger potential impact circle recalculated under paragraph (d)(2)(i) of this section.
	(ii) If personnel response time to mainline valves on either side of the high consequence area exceeds one hour (under normal driving conditions and speed limits) from the time the event is identified in the control room, provide remote valve control through a supervisory control and data acquisition (SCADA) system, other leak detection system, or an alternative method of control.
	(iii) Remote valve control must include the ability to close and monitor the valve position (open or closed), and monitor pressure upstream and downstream.
	(iv) A line break valve control system using differential pressure, rate of pressure drop or other widely-accepted method is an acceptable alternative to remote valve control.
(4) Protecting the right-of-way	(i) Patrol the right-of-way at intervals not exceeding 45 days, but at least 12 times each calendar year, to inspect for excavation activities, ground movement, wash outs, leakage, or other activities or conditions affecting the safety operation of the pipeline.

	(ii) Develop and implement a plan to monitor for and mitigate occurrences of unstable soil and ground movement.
	(iii) If observed conditions indicate the possible loss of cover, perform a depth of cover study and replace cover as necessary to restore the depth of cover or apply alternative means to provide protection equivalent to the originally-required depth of cover.
	(iv) Use line-of-sight line markers satisfying the requirements of § 192.707(d) except in agricultural areas, large water crossings or swamp, steep terrain, or where prohibited by Federal Energy Regulatory Commission orders, permits, or local law.
	(v) Review the damage prevention program under § 192.614(a) in light of national consensus practices, to ensure the program provides adequate protection of the right-of-way. Identify the standards or practices considered in the review and meet or exceed those standards or practices by incorporating appropriate changes into the program.
	(vi) Develop and implement a right-of-way management plan to protect the pipeline segment from damage due to excavation activities.
	(5) Controlling internal corrosion
	(ii) At points where gas with potentially deleterious contaminants enters the pipeline, use filter separators or separators and gas quality monitoring equipment.
	(iii) Use gas quality monitoring equipment that includes a moisture analyzer, chromatograph, and periodic hydrogen sulfide sampling.
	(iv) Use cleaning pigs and sample accumulated liquids. Use inhibitors when corrosive gas or liquids are present.
	(v) Address deleterious gas stream constituents as follows:
	(A) Limit carbon dioxide to 3 percent by volume;

	(B) Allow no free water and otherwise limit water to seven pounds per million cubic feet of gas; and
	(C) Limit hydrogen sulfide to 1.0 grain per hundred cubic feet (16 ppm) of gas, where the hydrogen sulfide is greater than 0.5 grain per hundred cubic feet (8 ppm) of gas, implement a pigging and inhibitor injection program to address deleterious gas stream constituents, including follow-up sampling and quality testing of liquids at receipt points.
	(vi) Review the program at least quarterly based on the gas stream experience and implement adjustments to monitor for, and mitigate the presence of, deleterious gas stream constituents.
(6) Controlling interference that can impact external corrosion	(i) Prior to operating an existing pipeline segment at an alternate maximum allowable operating pressure calculated under this section, or within six months after placing a new pipeline segment in service at an alternate maximum allowable operating pressure calculated under this section, address any interference currents on the pipeline segment.
	(ii) To address interference currents, perform the following:
	(A) Conduct an interference survey to detect the presence and level of any electrical current that could impact external corrosion where interference is suspected;
	(B) Analyze the results of the survey; and
	(C) Take any remedial action needed within 6 months after completing the survey to protect the pipeline segment from deleterious current.
(7) Confirming external corrosion control through indirect assessment	(i) Within six months after placing the cathodic protection of a new pipeline segment in operation, or within six months after certifying a segment under § 192.620(c)(1) of an existing pipeline segment under this section, assess the adequacy of the cathodic protection through an indirect method such as close-interval survey, and the integrity of the coating using direct current voltage

	gradient (DCVG) or alternating current voltage gradient (ACVG).
	(ii) Remediate any construction damaged coating with a voltage drop classified as moderate or severe (IR drop greater than 35% for DCVG or 50 dB μ v for ACVG) under section 4 of NACE RP-0502-2002 (incorporated by reference, see § 192.7).
	(iii) Within six months after completing the baseline internal inspection required under paragraph (d)(9) of this section, integrate the results of the indirect assessment required under paragraph (d)(7)(i) of this section with the results of the baseline internal inspection and take any needed remedial actions.
	(iv) For all pipeline segments in high consequence areas, perform periodic assessments as follows:
	(A) Conduct periodic close interval surveys with current interrupted to confirm voltage drops in association with periodic assessments under subpart O of this part.
	(B) Locate pipe-to-soil test stations at half-mile intervals within each high consequence area ensuring at least one station is within each high consequence area, if practicable.
	(C) Integrate the results with those of the baseline and periodic assessments for integrity done under paragraphs (d)(9) and (d)(10) of this section.
(8) Controlling external corrosion through cathodic protection	(i) If an annual test station reading indicates cathodic protection below the level of protection required in subpart I of this part, complete remedial action within six months of the failed reading or notify each PHMSA pipeline safety regional office where the pipeline is in service demonstrating that the integrity of the pipeline is not compromised if the repair takes longer than 6 months. An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State; and
	(ii) After remedial action to address a failed reading, confirm restoration of adequate corrosion

	<p>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.</p>
	<p>(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.</p>
(9) Conducting a baseline assessment of integrity	<p>(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:</p>
	<p>(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</p>
	<p>(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.</p>
	<p>(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.</p>
	<p>(iii) If headers, mainline valve by-passes, compressor station piping, meter station piping, or other short portion of a pipeline segment operating at alternative maximum allowable operating pressure cannot accommodate a geometry tool and a high resolution magnetic flux tool, use direct assessment (per § 192.925, § 192.927 and/or § 192.929) or pressure testing (per subpart J of this part) to assess that portion.</p>
(10) Conducting periodic assessments of integrity	<p>(i) Determine a frequency for subsequent periodic integrity assessments as if all the alternative maximum allowable operating pressure pipeline</p>

	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
	(ii) Repair a defect immediately if any of the following apply:
	(A) The defect is a dent discovered during the baseline assessment for integrity under paragraph (d)(9) of this section and the defect meets the criteria for immediate repair in § 192.309(b).
	(B) The defect meets the criteria for immediate repair in § 192.933(d).
	(C) The alternative maximum allowable operating pressure was based on a design factor of 0.67 under paragraph (a) of this section and the failure pressure is less than 1.25 times the alternative maximum allowable operating pressure.
	(D) The alternative maximum allowable operating pressure was based on a design factor of 0.56 under paragraph (a) of this section and the failure pressure is less than or equal to 1.4 times the alternative maximum allowable operating pressure.

	(iii) If paragraph (d)(11)(ii) of this section does not require immediate repair, repair a defect within one year if any of the following apply:
	(A) The defect meets the criteria for repair within one year in § 192.933(d).
	(B) The alternative maximum allowable operating pressure was based on a design factor of 0.80 under paragraph (a) of this section and the failure pressure is less than 1.25 times the alternative maximum allowable operating pressure.
	(C) The alternative maximum allowable operating pressure was based on a design factor of 0.67 under paragraph (a) of this section and the failure pressure is less than 1.50 times the alternative maximum allowable operating pressure.
	(D) The alternative maximum allowable operating pressure was based on a design factor of 0.56 under paragraph (a) of this section and the failure pressure is less than or equal to 1.80 times the alternative maximum allowable operating pressure.
	(iv) Evaluate any defect not required to be repaired under paragraph (d)(11)(ii) or (iii) of this section to determine its growth rate, set the maximum interval for repair or re-inspection, and repair or re-inspect within that interval.

(e)

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

~~(1)~~(5) Provide overpressure protection that limits mainline pressure to a maximum of 104 percent of the maximum allowable operating pressure; and

~~(2)~~(6) Develop and follow a procedure for establishing and maintaining accurate set points for the supervisory control and data acquisition system.

§ 192.621 Maximum Allowable Operating Pressure: High-Pressure Distribution Systems

- (a) No person may operate a segment of a high-pressure distribution system at a pressure that exceeds the lowest of the following pressures, as applicable:
 - (1) The design pressure of the weakest element in the segment, determined in accordance with Subparts C and D of this part.
 - (2) 60 p.s.i. (414 kPa) gage for a segment of a distribution system otherwise designed

to operate at over 60 p.s.i. (414 kPa) gage, unless the service lines in the segment are equipped with service regulators or other pressure limiting devices in series that meet the requirements of § 192.197(c).

- (3) 25 p.s.i. (172 kPa) gage in segments of cast iron pipe in which there are unreinforced bell and spigot joints.
 - (4) The pressure limits to which a joint could be subjected without the possibility of its parting.
 - (5) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressures.
- (b) No person may operate a segment of pipeline to which paragraph (a)(5) of this section applies, unless overpressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with § 192.195.
- (c) The maximum allowable operating pressure shall be designated following the above procedures and posted on system maps, drawings, regulator stations or other appropriate records.

§ 192.622 Maximum Actual Operating Pressure: High-Pressure Distribution Systems

- (a) Each operator shall establish a maximum actual operating pressure if the actual operating pressure is less than the established maximum allowable operating pressure. The maximum actual operating pressure will be the pressure for orifice sizing in customer regulators as required by § 192.197. The maximum actual operating pressure may be increased to a pressure not exceeding the maximum allowable operating pressure during emergency operating conditions. Normal seasonal gas demands are not considered emergency operating conditions. Upon termination of the emergency the pressure must be reduced to a pressure not exceeding the established maximum actual operating pressure. The maximum actual operating pressure shall be posted on system maps, drawings, regulator stations or other appropriate records.
- (b) Before increasing the established maximum actual operating pressure, under normal conditions, the operator shall:
- (1) Calculate the rated capability of each overpressure control device installed at each customer's service.
 - (2) If the overpressure control device is not capable of maintaining a safe pressure to the customer's gas utilization equipment, a new or additional device must be installed to provide a safe pressure to the customer.

§ 192.623 Maximum and Minimum Allowable Operating Pressure: Low-Pressure Distribution Systems

- (a) No person may operate a low-pressure distribution system at a pressure high enough to make unsafe the operation of any connected and properly adjusted low-pressure gas burning equipment.
- (b) No person may operate a low-pressure distribution system at a pressure lower than the minimum pressure at which the safe and continuing operation of any connected and properly adjusted low-pressure gas burning equipment can be assured.

§ 192.624 Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines

- (a) *Applicability.* Operators of onshore steel transmission pipeline segments must reconfirm the maximum allowable operating pressure (MAOP) of all pipeline segments in accordance with the requirements of this section if either of the following conditions are met:
- (1) Records necessary to establish the MAOP in accordance with § 192.619(a)(2), including records required by § 192.517(a), are not traceable, verifiable, and complete and the pipeline is located in one of the following locations:
 - (i) A high consequence area as defined in § 192.903; or
 - (ii) A Class 3 or Class 4 location.
 - (2) The pipeline segment's MAOP was established in accordance with § 192.619(c), the pipeline segment's MAOP is greater than or equal to 30 percent of the specified minimum yield strength, and the pipeline segment is located in one of the following areas:
 - (i) A high consequence area as defined in § 192.903;
 - (ii) A Class 3 or Class 4 location; or
 - (iii) A moderate consequence area as defined in § 192.3, if the pipeline segment can accommodate inspection by means of instrumented inline inspection tools.
- (b) *Procedures and completion dates.* Operators of a pipeline subject to this section must develop and document procedures for completing all actions required by this section by July 1, 2021. These procedures must include a process for reconfirming MAOP for any pipelines that meet a condition of § 192.624(a), and for performing a spike test or material verification in accordance with §§ 192.506 and 192.607, if applicable. All actions required by this section must be completed according to the following schedule:
- (1) Operators must complete all actions required by this section on at least 50% of the pipeline mileage by July 3, 2028.
 - (2) Operators must complete all actions required by this section on 100% of the pipeline mileage by July 2, 2035 or as soon as practicable, but not to exceed 4 years after the pipeline segment first meets a condition of § 192.624(a) (e.g., due to a location becoming a high consequence area), whichever is later.
 - (3) If operational and environmental constraints limit an operator from meeting the deadlines in § 192.624, the operator may petition for an extension of the completion deadlines by up to 1 year, upon submittal of a notification in accordance with § 192.18. The notification must include an up-to-date plan for completing all actions in accordance with this section, the reason for the requested extension, current status, proposed completion date, outstanding remediation activities, and any needed temporary measures needed to mitigate the impact on safety.
- (c) *Maximum allowable operating pressure determination.* Operators of a pipeline segment meeting a condition in paragraph (a) of this section must reconfirm its MAOP using one of the following methods:
- (1) *Method 1: Pressure test.* Perform a pressure test and verify material properties records in accordance with § 192.607 and the following requirements:

- (i) *Pressure test.* Perform a pressure test in accordance with subpart J of this part. The MAOP must be equal to the test pressure divided by the greater of either 1.25 or the applicable class location factor in § 192.619(a)(2)(ii).
 - (ii) *Material properties records.* Determine if the following material properties records are documented in traceable, verifiable, and complete records: Diameter, wall thickness, seam type, and grade (minimum yield strength, ultimate tensile strength).
 - (iii) *Material properties verification.* If any of the records required by paragraph (c)(1)(ii) of this section are not documented in traceable, verifiable, and complete records, the operator must obtain the missing records in accordance with § 192.607. An operator must test the pipe materials cut out from the test manifold sites at the time the pressure test is conducted. If there is a failure during the pressure test, the operator must test any removed pipe from the pressure test failure in accordance with § 192.607.
- (2) *Method 2: Pressure Reduction.* Reduce pressure, as necessary, and limit MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by the greater of 1.25 or the applicable class location factor in § 192.619(a)(2)(ii). The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during a continuous 30-day period. The value used as the highest actual sustained operating pressure must account for differences between upstream and downstream pressure on the pipeline by use of either the lowest maximum pressure value for the entire pipeline segment or using the operating pressure gradient along the entire pipeline segment (*i.e.*, the location-specific operating pressure at each location).
- (i) Where the pipeline segment has had a class location change in accordance with § 192.611, and records documenting diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), and pressure tests are not documented in traceable, verifiable, and complete records, the operator must reduce the pipeline segment MAOP as follows:
 - (A) For pipeline segments where a class location changed from Class 1 to Class 2, from Class 2 to Class 3, or from Class 3 to Class 4, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by 1.39 for Class 1 to Class 2, 1.67 for Class 2 to Class 3, and 2.00 for Class 3 to Class 4.
 - (B) For pipeline segments where a class location changed from Class 1 to Class 3, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by 2.00.
 - (ii) Future uprating of the pipeline segment in accordance with subpart K is allowed if the MAOP is established using Method 2.
 - (iii) If an operator elects to use Method 2, but desires to use a less conservative pressure reduction factor or longer look-back period, the operator must notify PHMSA in accordance with § 192.18 no later than 7 calendar days after establishing the reduced MAOP. The notification must include the following details:

- (A) Descriptions of the operational constraints, special circumstances, or other factors that preclude, or make it impractical, to use the pressure reduction factor specified in § 192.624(c)(2);
 - (B) The fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis that complies with § 192.712;
 - (C) Justification that establishing MAOP by another method allowed by this section is impractical;
 - (D) Justification that the reduced MAOP determined by the operator is safe based on analysis of the condition of the pipeline segment, including material properties records, material properties verified in accordance § 192.607, and the history of the pipeline segment, particularly known corrosion and leakage, and the actual operating pressure, and additional compensatory preventive and mitigative measures taken or planned; and
 - (E) Planned duration for operating at the requested MAOP, long-term remediation measures and justification of this operating time interval, including fracture mechanics modeling for failure stress pressures and cyclic fatigue growth analysis and other validated forms of engineering analysis that have been reviewed and confirmed by subject matter experts.
- (3) *Method 3: Engineering Critical Assessment (ECA)*. Conduct an ECA in accordance with § 192.632.
 - (4) *Method 4: Pipe Replacement*. Replace the pipeline segment in accordance with this part.
 - (5) *Method 5: Pressure Reduction for Pipeline Segments with Small Potential Impact Radius*. Pipelines with a potential impact radius (PIR) less than or equal to 150 feet may establish the MAOP as follows:
 - (i) Reduce the MAOP to no greater than the highest actual operating pressure sustained by the pipeline during 5 years preceding October 1, 2019, divided by 1.1. The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during one continuous 30-day period. The reduced MAOP must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest value for the entire pipeline segment or the operating pressure gradient (*i.e.*, the location specific operating pressure at each location);
 - (ii) Conduct patrols in accordance with § 192.705 paragraphs (a) and (c) and conduct instrumented leakage surveys in accordance with § 192.706 at intervals not to exceed those in the following table 1 to § 192.624(c)(5)(ii):

Table 1 to § 192.624(c)(5)(ii)

Class locations	Patrols	Leakage surveys
-----------------	---------	-----------------

(A) Class 1 and Class 2	3 ½ months, but at least four times each calendar year	3 ½ months, but at least four times each calendar year.
(B) Class 3 and Class 4	3 months, but at least six times each calendar year	3 months, but at least six times each calendar year.

- (iii) Under Method 5, future uprating of the pipeline segment in accordance with subpart K is allowed.
- (6) *Method 6: Alternative Technology.* Operators may use an alternative technical evaluation process that provides a documented engineering analysis for establishing MAOP. If an operator elects to use alternative technology, the operator must notify PHMSA in advance in accordance with § 192.18. The notification must include descriptions of the following details:
 - (i) The technology or technologies to be used for tests, examinations, and assessments; the method for establishing material properties; and analytical techniques with similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the pipeline segment being evaluated;
 - (ii) Procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects and flaws, and remediate defects discovered;
 - (iii) Pipeline segment data, including original design, maintenance and operating history, anomaly or flaw characterization;
 - (iv) Assessment techniques and acceptance criteria, including anomaly detection confidence level, probability of detection, and uncertainty of the predicted failure pressure quantified as a fraction of specified minimum yield strength;
 - (v) If any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph § 192.712;
 - (vi) Operational monitoring procedures;
 - (vii) Methodology and criteria used to justify and establish the MAOP; and
 - (viii) Documentation of the operator's process and procedures used to implement the use of the alternative technology, including any records generated through its use.
- (d) *Records.* An operator must retain records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this section for the life of the pipeline.

§ 192.625 Odorization of Gas

- (a) A combustible gas in a distribution line must contain a natural odorant or be odorized so

that at a concentration in air of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell.

- (b) After December 31, 1976, a combustible gas in a transmission line in a Class 3 or Class 4 location must comply with the requirements of paragraph (a) of this section unless:
- (1) At least 50 percent of the length of the line downstream from that location is in a Class 1 or Class 2 location;
 - (2) The line transports gas to any of the following facilities which received gas without an odorant from that line before May 5, 1975;
 - (i) An underground storage field;
 - (ii) A gas processing plant;
 - (iii) A gas dehydration plant; or
 - (iv) An industrial plant using gas in a process where the presence of an odorant:
 - (A) Makes the end product unfit for the purpose for which it is intended;
 - (B) Reduces the activity of a catalyst; or
 - (C) Reduces the percentage completion of a chemical reaction;
 - (3) In the case of a lateral line which transports gas to a distribution center, at least 50 percent of the length of that line is in a Class 1 or Class 2 location; or
 - (4) The combustible gas is hydrogen intended for use as a feedstock in a manufacturing process.
- (c) In the concentrations in which it is used, the odorant in combustible gases must comply with the following:
- (1) The odorant must not be harmful to persons, materials, or pipes.
 - (2) The products of combustion from the odorant may not be toxic when breathed nor may they be corrosive or harmful to those materials to which the products of combustion will be exposed.
- (d) The odorant may not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight.
- (e) Equipment for odorization must introduce the odorant without wide variations in the level of odorant.
- ~~(f)~~ To assure the proper concentration of odorant in accordance with this section, each operator must conduct periodic sampling of combustible gases using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable. Operators of master meter systems may comply with this requirement by:
- (1) Receiving written verification from their gas source that the gas has the proper concentration of odorant, or
 - ~~(1)~~(2) Conducting periodic "sniff" tests at the extremities of the system to confirm that the gas contains odorant.
- ~~(f)(g)~~ Each operator shall conduct an odorant concentration test by ~~performing a room odorant test or~~ measuring with an instrument designed for this purpose. Systems odorized by centrally located equipment and designed to provide properly odorized gas to a large

number of customers, shall have test points at key locations where odorant concentration tests shall be taken. These test points shall be designated in such a manner to allow sampling of gas at the furthest points from the odorizer(s). These tests shall be conducted at intervals not exceeding 3 months and recorded. ~~As a minimum, r~~Records of the ~~most~~ current year and ~~the two years immediately preceding the most current year~~ previous test shall be maintained by the operator and provided to the Pipeline Safety Office upon request.

~~(g)~~(h) Individual taps from unodorized facilities shall be provided with odorization equipment of proper size and serviced frequently enough to ensure an ample supply of odorant at all times. Odorant concentration test of this type facility shall be conducted each six months, not to exceed 7 months, by an acceptable method with an instruments designed for this purpose. Odorant test records of the ~~most~~ current year and ~~the two years immediately preceding the current year~~ previous test of each customer shall be maintained by the operator and provided to the Pipeline Safety Office upon request.

§ 192.627 Tapping Pipelines Under Pressure

Each tap made on a pipeline under pressure must be performed by a crew qualified to make hot taps.

§ 192.629 Purging of Pipelines

- (a) When a pipeline is being purged of air by use of gas, the gas must be released into one end of the line in a moderately rapid and continuous flow. If gas cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the gas.
- (b) When a pipeline is being purged of gas by use of air, the air must be released into one end of the line in a moderately rapid and continuous flow. If air cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the air.
- (c) When a low pressure gas system is being purged of water by natural gas, the allowable operating pressure may not be exceeded. If the pressure required to purge the water exceeds the established maximum allowable operating pressure, air will be used to purge the system.

§ 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;
 - (4) A method of recording controller shift-changes and any hand-over of responsibility between controllers; and
 - (5) The roles, responsibilities and qualifications of others with the authority to direct and supersede the specific technical actions of a controller.
- (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;

- (2) Establish shift lengths and schedule rotations that provide controllers off-duty time sufficient to achieve eight hours of continuous sleep;
 - (3) Educate controllers and supervisors in fatigue mitigation strategies and how off-duty activities contribute to fatigue.
 - (4) Train controllers and supervisors to recognize the effects of fatigue; and
 - (5) 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:

- (xxv) Controller fatigue;
 - (xxvi) Field equipment;
 - (xxvii) The operation of any relief device;
 - (xxviii) Procedures;
 - (xxix) SCADA system configuration; and
 - (xxx) 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 or 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;
 - (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; and
 - (6) Control room team training and exercises that include both controllers and other individuals, defined by the operator, who would reasonably be expected to operationally collaborate with controllers (control room personnel) during normal, abnormal or emergency situations. Operators must comply with the team training requirements under this paragraph by no later than January 23, 2018.
- (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.

**§ 192.632 Engineering Critical Assessment for Maximum Allowable Operating Pressure
Reconfirmation: Onshore steel transmission pipelines**

When an operator conducts an MAOP reconfirmation in accordance with § 192.624(c)(3) "Method 3"

using an ECA to establish the material strength and MAOP of the pipeline segment, the ECA must comply with the requirements of this section. The ECA must assess: Threats; loadings and operational circumstances relevant to those threats, including along the pipeline right-of way; outcomes of the threat assessment; relevant mechanical and fracture properties; in-service degradation or failure processes; and initial and final defect size relevance. The ECA must quantify the interacting effects of threats on any defect in the pipeline.

(a) *ECA Analysis.*

- (1) The material properties required to perform an ECA analysis in accordance with this paragraph are as follows: Diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), and Charpy v-notch toughness values based upon the lowest operational temperatures, if applicable. If any material properties required to perform an ECA for any pipeline segment in accordance with this paragraph are not documented in traceable, verifiable and complete records, an operator must use conservative assumptions and include the pipeline segment in its program to verify the undocumented information in accordance with § 192.607. The ECA must integrate, analyze, and account for the material properties, the results of all tests, direct examinations, destructive tests, and assessments performed in accordance with this section, along with other pertinent information related to pipeline integrity, including close interval surveys, coating surveys, interference surveys required by subpart I of this part, cause analyses of prior incidents, prior pressure test leaks and failures, other leaks, pipe inspections, and prior integrity assessments, including those required by §§ 192.617, 192.710, and subpart O of this part.
- (2) The ECA must analyze and determine the predicted failure pressure for the defect being assessed using procedures that implement the appropriate failure criteria and justification as follows:
 - (i) The ECA must analyze any cracks or crack-like defects remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure of each defect in accordance with § 192.712.
 - (ii) The ECA must analyze any metal loss defects not associated with a dent, including corrosion, gouges, scrapes or other metal loss defects that could remain in the pipe, to determine the predicted failure pressure. ASME/ANSI B31G (incorporated by reference, see § 192.7) or R-STRENG (incorporated by reference, see § 192.7) must be used for corrosion defects. Both procedures and their analysis apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations' procedures. The ECA must use conservative assumptions for metal loss dimensions (length, width, and depth).
 - (iii) When determining the predicted failure pressure for gouges, scrapes, selective seam weld corrosion, crack-related defects, or any defect within a dent, appropriate failure criteria and justification of the criteria must be used and documented.
 - (iv) If SMYS or actual material yield and ultimate tensile strength is not known or not documented by traceable, verifiable, and complete records, then the operator must assume 30,000 p.s.i. or determine the material properties using § 192.607.

- (3) The ECA must analyze the interaction of defects to conservatively determine the most limiting predicted failure pressure. Examples include, but are not limited to, cracks in or near locations with corrosion metal loss, dents with gouges or other metal loss, or cracks in or near dents or other deformation damage. The ECA must document all evaluations and any assumptions used in the ECA process.
 - (4) The MAOP must be established at the lowest predicted failure pressure for any known or postulated defect, or interacting defects, remaining in the pipe divided by the greater of 1.25 or the applicable factor listed in § 192.619(a)(2)(ii).
- (b) *Assessment to determine defects remaining in the pipe.* An operator must utilize previous pressure tests or develop and implement an assessment program to determine the size of defects remaining in the pipe to be analyzed in accordance with paragraph (a) of this section.
- (1) An operator may use a previous pressure test that complied with subpart J to determine the defects remaining in the pipe if records for a pressure test meeting the requirements of subpart J of this part exist for the pipeline segment. The operator must calculate the largest defect that could have survived the pressure test. The operator must predict how much the defects have grown since the date of the pressure test in accordance with § 192.712. The ECA must analyze the predicted size of the largest defect that could have survived the pressure test that could remain in the pipe at the time the ECA is performed. The operator must calculate the remaining life of the most severe defects that could have survived the pressure test and establish a re-assessment interval in accordance with the methodology in § 192.712.
 - (2) Operators may use an inline inspection program in accordance with paragraph (c) of this section.
 - (3) Operators may use “other technology” if it is validated by a subject matter expert to produce an equivalent understanding of the condition of the pipe equal to or greater than pressure testing or an inline inspection program. If an operator elects to use “other technology” in the ECA, it must notify PHMSA in advance of using the other technology in accordance with § 192.18. The “other technology” notification must have:
 - (i) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments, including characterization of defect size used in the crack assessments (length, depth, and volumetric); and
 - (ii) Procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects, and remediate defects discovered.
- (c) *In-line inspection.* An inline inspection (ILI) program to determine the defects remaining the pipe for the ECA analysis must be performed using tools that can detect wall loss, deformation from dents, wrinkle bends, ovalities, expansion, seam defects, including cracking and selective seam weld corrosion, longitudinal, circumferential and girth weld cracks, hard spot cracking, and stress corrosion cracking.
- (1) If a pipeline has segments that might be susceptible to hard spots based on assessment, leak, failure, manufacturing vintage history, or other information, then the ILI program must include a tool that can detect hard spots.
 - (2) If the pipeline has had a reportable incident, as defined in § 191.3, attributed to a girth weld failure since its most recent pressure test, then the ILI program must

include a tool that can detect girth weld defects unless the ECA analysis performed in accordance with this section includes an engineering evaluation program to analyze and account for the susceptibility of girth weld failure due to lateral stresses.

- (3) Inline inspection must be performed in accordance with § 192.493.
 - (4) An operator must use unity plots or equivalent methodologies to validate the performance of the ILI tools in identifying and sizing actionable manufacturing and construction related anomalies. Enough data points must be used to validate tool performance at the same or better statistical confidence level provided in the tool specifications. The operator must have a process for identifying defects outside the tool performance specifications and follow up with the ILI vendor to conduct additional in-field examinations, reanalyze ILI data, or both.
 - (5) Interpretation and evaluation of assessment results must meet the requirements of §§ 192.710, 192.713, and subpart O of this part, and must conservatively account for the accuracy and reliability of ILI, in-the-ditch examination methods and tools, and any other assessment and examination results used to determine the actual sizes of cracks, metal loss, deformation and other defect dimensions by applying the most conservative limit of the tool tolerance specification. ILI and in-the-ditch examination tools and procedures for crack assessments (length and depth) must have performance and evaluation standards confirmed for accuracy through confirmation tests for the defect types and pipe material vintage being evaluated. Inaccuracies must be accounted for in the procedures for evaluations and fracture mechanics models for predicted failure pressure determinations.
 - (6) Anomalies detected by ILI assessments must be remediated in accordance with applicable criteria in §§ 192.713 and 192.933.
- (d) *Defect remaining life.* If any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with § 192.712.
- (e) *Records.* An operator must retain records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this section for the life of the pipeline.

§ 192.634 Transmission lines: Onshore valve shut-off for rupture mitigation.

- (a) *Applicability.* For new or entirely replaced onshore transmission pipeline segments with diameters of 6 inches or greater that are located in high-consequence areas (HCA) or Class 3 or Class 4 locations and that are installed after April 10, 2023, an operator must install or use existing rupture-mitigation valves (RMV), or an alternative equivalent technology, according to the requirements of this section and §§ 192.179 and 192.636. RMVs and alternative equivalent technologies must be operational within 14 days of placing the new or replaced pipeline segment into service. An operator may request an extension of this 14-day operation requirement if it can demonstrate to PHMSA, in accordance with the notification procedures in § 192.18, that application of that requirement would be economically, technically, or operationally infeasible. The requirements of this section apply to all applicable pipe replacement projects, even those

that do not otherwise involve the addition or replacement of a valve. This section does not apply to pipe segments in Class 1 or Class 2 locations that have a potential impact radius (PIR), as defined in § 192.903, that is less than or equal to 150 feet.

(b) *Maximum spacing between valves.* RMVs, or alternative equivalent technology, must be installed in accordance with the following requirements:

(1) *Shut-off segment.* For purposes of this section, a “shut-off segment” means the segment of pipe located between the upstream valve closest to the upstream endpoint of the new or replaced Class 3 or Class 4 or HCA pipeline segment and the downstream valve closest to the downstream endpoint of the new or replaced Class 3 or Class 4 or HCA pipeline segment so that the entirety of the segment that is within the HCA or the Class 3 or Class 4 location is between at least two RMVs or alternative equivalent technologies. If any crossover or lateral pipe for gas receipts or deliveries connects to the shut-off segment between the upstream and downstream valves, the shut-off segment also must extend to a valve on the crossover connection(s) or lateral(s), such that, when all valves are closed, there is no flow path for gas to be transported to the rupture site (except for residual gas already in the shut-off segment). Multiple Class 3 or Class 4 locations or HCA segments may be contained within a single shut-off segment. The operator is not required to select the closest valve to the shut-off segment as the RMV, as that term is defined in § 192.3, or the alternative equivalent technology. An operator may use a manual compressor station valve at a continuously manned station as an alternative equivalent technology, but it must be able to be closed within 30 minutes following rupture identification, as that term is defined at § 192.3. Such a valve used as an alternative equivalent technology would not require a notification to PHMSA in accordance with § 192.18.

(2) *Shut-off segment valve spacing.* A pipeline subject to paragraph (a) of this section must have RMVs or alternative equivalent technology on the upstream and downstream side of the pipeline segment. The distance between RMVs or alternative equivalent technologies must not exceed:

(i) Eight (8) miles for any Class 4 location,

(ii) Fifteen (15) miles for any Class 3 location, or

(iii) Twenty (20) miles for all other locations.

(3) *Laterals.* Laterals extending from shut-off segments that contribute less than 5 percent of the total shut-off segment volume may have RMVs or alternative equivalent technologies that meet the actuation requirements of this section at locations other than mainline receipt/delivery points, as long as all of the laterals contributing gas volumes to the shut-off segment do not contribute more than 5 percent of the total shut-off segment gas volume based upon maximum flow volume at the operating pressure. For laterals that are 12 inches in diameter or less, a check valve that allows gas to flow freely in one direction and contains a

mechanism to automatically prevent flow in the other direction may be used as an alternative equivalent technology where it is positioned to stop flow into the shut-off segment. Such check valves that are used as an alternative equivalent technology in accordance with this paragraph (b)(3) are not subject to § 192.636, but they must be inspected, operated, and remediated in accordance with § 192.745, including for closure and leakage to ensure operational reliability. An operator using such a check valve as an alternative equivalent technology must notify PHMSA in accordance with §§ 192.18 and 192.179 and develop and implement maintenance procedures for such equipment that meet § 192.745.

(4) Crossovers. An operator may use a manual valve as an alternative equivalent technology in lieu of an RMV for a crossover connection if, during normal operations, the valve is closed to prevent the flow of gas by the use of a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator. The operator must develop and implement operating procedures and document that the valve has been closed and locked in accordance with the operator's lock-out and tag-out procedures to prevent the flow of gas. An operator using such a manual valve as an alternative equivalent technology must notify PHMSA in accordance with §§ 192.18 and 192.179.

~~(c) Manual operation upon identification of a rupture. Operators using a manual valve as an alternative equivalent technology as authorities pursuant to §§ 192.18 and 192.179 must develop and implement operating procedures that appropriately designate and locate nearby personnel to ensure valve shut off in accordance with this section and § 192.636. Manual operation of valves must include time for the assembly of necessary operating personnel, the acquisition of necessary tools and equipment, driving time under heavy traffic conditions and at the posted speed limit, walking time to access the valve, and time to shut off all valves manually, not to exceed the maximum response time allowed under § 192.636(b).~~

§ 192.635 Notification of potential rupture.

(a) As used in this part, a “notification of potential rupture” refers to the notification of, or observation by, an operator (e.g., by or to its controller(s) in a control room, field personnel, nearby pipeline or utility personnel, the public, local responders, or public authorities) of one or more of the below indicia of a potential unintentional or uncontrolled release of a large volume of gas from a pipeline:

(1) An unanticipated or unexplained pressure loss outside of the pipeline's normal operating pressures, as defined in the operator's written procedures. The operator must establish in its written procedures that an unanticipated or unplanned pressure loss is outside of the pipeline's normal operating pressures when there is a pressure loss greater than 10 percent occurring within a time interval of 15 minutes or less, unless the operator has documented in its written procedures the operational need for a greater pressure-change threshold due to pipeline flow dynamics (including changes in operating pressure, flow rate, or volume), that are caused by fluctuations in gas demand, gas receipts, or gas deliveries; or

- (2) An unanticipated or unexplained flow rate change, pressure change, equipment function, or other pipeline instrumentation indication at the upstream or downstream station that may be representative of an event meeting paragraph (a)(1) of this section; or
- (3) Any unanticipated or unexplained rapid release of a large volume of gas, a fire, or an explosion in the immediate vicinity of the pipeline.
- (b) A notification of potential rupture occurs when an operator first receives notice of or observes an event specified in paragraph (a) of this section.
- (c) This section does not apply to any gas gathering line.

§ 192.636 Transmission lines: Response to a rupture; capabilities of rupture-mitigation valves (RMVs) or alternative equivalent technologies.

- (a) Scope. The requirements in this section apply to rupture-mitigation valves (RMVs), as defined in § 192.3, or alternative equivalent technologies, installed pursuant to §§ 192.179(e), (f), and (g) and 192.634.
- (b) Rupture identification and valve shut-off time. An operator must, as soon as practicable but within 30 minutes of rupture identification (see § 192.615(a)(12)), fully close any RMVs or alternative equivalent technologies necessary to minimize the volume of gas released from a pipeline and mitigate the consequences of a rupture.
- (c) Open valves. An operator may leave an RMV or alternative equivalent technology open for more than 30 minutes, as required by paragraph (b) of this section, if the operator has previously established in its operating procedures and demonstrated within a notice submitted under § 192.18 for PHMSA review, that closing the RMV or alternative equivalent technology would be detrimental to public safety. The request must have been coordinated with appropriate local emergency responders, and the operator and emergency responders must determine that it is safe to leave the valve open. Operators must have written procedures for determining whether to leave an RMV or alternative equivalent technology open, including plans to communicate with local emergency responders and minimize environmental impacts, which must be submitted as part of its notification to PHMSA.
- (d) Valve monitoring and operation capabilities. An RMV, as defined in § 192.3, or alternative equivalent technology, must be capable of being monitored or controlled either remotely or by on-site personnel as follows:
 - (1) Operated during normal, abnormal, and emergency operating conditions;
 - (2) Monitored for valve status (i.e., open, closed, or partial closed/open), upstream pressure, and downstream pressure. For automatic shut-off valves (ASV), an operator does not need to monitor remotely a valve's status if the operator has the capability to monitor pressures or gas flow rate within each pipeline segment

located between RMVs or alternative equivalent technologies to identify and locate a rupture. Pipeline segments that use manual valves or other alternative equivalent technologies must have the capability to monitor pressures or gas flow rates on the pipeline to identify and locate a rupture; and

- (3) Have a back-up power source to maintain SCADA systems or other remote communications for remote-control valve (RCV) or automatic shut-off valve (ASV) operational status, or be monitored and controlled by on-site personnel.
- (e) *Monitoring of valve shut-off response status.* The position and operational status of an RMV must be appropriately monitored through electronic communication with remote instrumentation or other equivalent means. An operator does not need to monitor remotely an ASV's status if the operator has the capability to monitor pressures or gas flow rate on the pipeline to identify and locate a rupture.
- (f) *Flow modeling for automatic shut-off valves.* Prior to using an ASV as an RMV, an operator must conduct flow modeling for the shut-off segment and any laterals that feed the shut-off segment, so that the valve will close within 30 minutes or less following rupture identification, consistent with the operator's procedures, and in accordance with § 192.3 and this section. The flow modeling must include the anticipated maximum, normal, or any other flow volumes, pressures, or other operating conditions that may be encountered during the year, not exceeding a period of 15 months, and it must be modeled for the flow between the RMVs or alternative equivalent technologies, and any looped pipelines or gas receipt tie-ins. If operating conditions change that could affect the ASV set pressures and the 30-minute valve closure time after notification of potential rupture, as defined at § 192.3, an operator must conduct a new flow model and reset the ASV set pressures prior to the next review for ASV set pressures in accordance with § 192.745. The flow model must include a time/pressure chart for the segment containing the ASV if a rupture occurs. An operator must conduct this flow modeling prior to making flow condition changes in a manner that could render the 30-minute valve closure time unachievable.
- (g) *Manual valves in non-HCA, Class 1 locations.* For pipeline segments in a Class 1 location that do not meet the definition of a high consequence area (HCA), an operator submitting a notification pursuant to §§ 192.18 and 192.179 for use of manual valves as an alternative equivalent technology may also request an exemption from the requirements of § 192.636(b).
- (h) *Manual operation upon identification of a rupture.* Operators using a manual valve as an alternative equivalent technology as authorized pursuant to §§ 192.18, 192.179, and 192.634 and this section must develop and implement operating procedures that appropriately designate and locate nearby personnel to ensure valve shutoff in accordance with this section and § 192.634. Manual operation of valves must include time for the assembly of necessary operating personnel, the acquisition of necessary tools and equipment, driving time under heavy traffic conditions and at the posted speed limit, walking time to access the valve, and time to shut off all valves manually, not to exceed the maximum response time allowed under paragraph (b) or (c) of this section.

SUBPART M - MAINTENANCE

§ 192.701 Scope

This subpart prescribes minimum requirements for maintenance of pipeline facilities.

§ 192.703 General

- (a) No person may operate a segment of pipeline, unless it is maintained in accordance with this subpart.
- (b) Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service.
- (c) Hazardous leaks must be repaired promptly.

§ 192.705 Transmission Lines: Patrolling

- (a) Each operator shall have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation.
- (b) The frequency of patrols is determined by the size of the line, the operating pressure, the class location, terrain, weather, and other relevant factors, but intervals between patrols may not be longer than prescribed in the following table:

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

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

§ 192.706 Transmission Lines: Leakage Surveys

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

- (a) In Class 3 locations, at intervals not exceeding 7 1/2 months, but at least twice each calendar year; and
- (b) In Class 4 locations, at intervals not exceeding 4 1/2 months, but at least four times each calendar year.

| _____

§ 192.707 Line Markers for Mains and Transmission Lines

- (a) *Buried pipelines.* Except as provided in paragraph (b) of this section, a line marker must be placed and maintained as close as practical over each buried main and transmission line:
- (1) At each crossing of a public road and railroad; and
 - (2) Wherever necessary to identify the location of the transmission line or main to reduce the possibility of damage or interference. When a pipeline crosses a divided roadway, a marker shall be placed on each side of the roadway.
- (b) *Exceptions for buried pipelines.* Line markers are not required for the following pipelines:
- (1) Mains and transmission lines located at crossings of or under waterways and other bodies of water.
 - (2) Mains in Class 3 or Class 4 locations where a damage prevention program is in effect under
§ 192.614:
 - (3) Transmission lines in Class 3 or 4 locations where placement of a line marker is impractical.
- (c) *Pipelines above ground.* Line markers must be placed and maintained along each section of a main and transmission line that is located above-ground in an area accessible to the public.
- (d) *Marker warning.* The following must be written legibly on a background of sharply contrasting color on each line marker:
- (1) The word "Warning", "Caution", or "Danger", followed by the words "Gas Pipeline" all of which, except for markers in heavily developed urban areas, must be in letters at least one inch (25 millimeters) high with one-quarter inch (6.4 millimeters) stroke.
 - (2) The name of the operator and the telephone number (including area code) where the operator can be reached at all times.

§ 192.709 Transmission Lines: Record-Keeping

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

- (a) The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipe remains in service.
- (b) The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 5 years. However, repairs generated by patrols, surveys, inspections, or tests required by subparts L and M of this part must be retained in accordance with paragraph (c) of this section.
- (c) A record of each patrol, survey, inspection, and test required by subparts L and M of this part must be retained for at least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.

§ 192.710 Transmission lines: Assessments outside of high consequence areas

- (a) *Applicability:* This section applies to onshore steel transmission pipeline segments with a maximum allowable operating pressure of greater than or equal to 30% of the

specified minimum yield strength and are located in:

- (1) A Class 3 or Class 4 location; or
- (2) A moderate consequence area as defined in § 192.3, if the pipeline segment can accommodate inspection by means of an instrumented inline inspection tool (i.e., “smart pig”).
- (3) This section does not apply to a pipeline segment located in a high consequence area as defined in § 192.903.

(b) *General -*

- (1) *Initial assessment.* An operator must perform initial assessments in accordance with this section based on a risk-based prioritization schedule and complete initial assessment for all applicable pipeline segments no later than July 3, 2034, or as soon as practicable but not to exceed 10 years after the pipeline segment first meets the conditions of § 192.710(a) (e.g., due to a change in class location or the area becomes a moderate consequence area), whichever is later.
- (2) *Periodic reassessment.* An operator must perform periodic reassessments at least once every 10 years, with intervals not to exceed 126 months, or a shorter reassessment interval based upon the type of anomaly, operational, material, and environmental conditions found on the pipeline segment, or as necessary to ensure public safety.
- (3) *Prior assessment.* An operator may use a prior assessment conducted before July 1, 2020 as an initial assessment for the pipeline segment, if the assessment met the subpart O requirements of part 192 for in-line inspection at the time of the assessment. If an operator uses this prior assessment as its initial assessment, the operator must reassess the pipeline segment according to the reassessment interval specified in paragraph (b)(2) of this section calculated from the date of the prior assessment.
- (4) *MAOP verification.* An integrity assessment conducted in accordance with the requirements of § 192.624(c) for establishing MAOP may be used as an initial assessment or reassessment under this section.

(c) *Assessment method.* The initial assessments and the reassessments required by paragraph (b) of this section must be capable of identifying anomalies and defects associated with each of the threats to which the pipeline segment is susceptible and must be performed using one or more of the following methods:

- (1) *Internal inspection.* Internal inspection tool or tools capable of detecting those threats to which the pipeline is susceptible, such as corrosion, deformation and mechanical damage (e.g., dents, gouges and grooves), material cracking and crack-like defects (e.g., stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493;
- (2) *Pressure test.* Pressure test conducted in accordance with subpart J of this part. The use of subpart J pressure testing is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms; manufacturing and related defect threats, including defective pipe and pipe seams; and stress corrosion cracking, selective seam weld corrosion,

- dents and other forms of mechanical damage;
- (3) *Spike hydrostatic pressure test.* A spike hydrostatic pressure test conducted in accordance with § 192.506. A spike hydrostatic pressure test is appropriate for time-dependent threats such as stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects;
 - (4) *Direct examination.* Excavation and in situ direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all applicable threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), Inverse Wave Field Extrapolation (IWEX), radiography, and magnetic particle inspection (MPI);
 - (5) *Guided Wave Ultrasonic Testing.* Guided Wave Ultrasonic Testing (GWUT) as described in Appendix F;
 - (6) *Direct assessment.* Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in §§ 192.925, 192.927 and 192.929; or
 - (7) *Other technology.* Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify PHMSA in advance of using the other technology in accordance with § 192.18.
- (d) *Data analysis.* An operator must analyze and account for the data obtained from an assessment performed under paragraph (c) of this section to determine if a condition could adversely affect the safe operation of the pipeline using personnel qualified by knowledge, training, and experience. In addition, when analyzing inline inspection data, an operator must account for uncertainties in reported results (e.g., tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies.
 - (e) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that 180 days is impracticable.
 - (f) *Remediation.* An operator must comply with the requirements in §§ 192.485, 192.711, ~~192.712, and~~ 192.713, and 192.714 where applicable, if a condition that could adversely affect the safe operation of a pipeline is discovered.
 - (g) *Analysis of information.* An operator must analyze and account for all available relevant

information about a pipeline in complying with the requirements in paragraphs (a) through (f) of this section.

§ 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. (1)~~
 - (i) Non-integrity management repairs for gathering lines and offshore transmission lines: For gathering lines subject to this section in accordance with § 192.9 and for offshore transmission lines, an operator must make permanent repairs as soon as feasible.
 - (ii) Non-integrity management repairs for onshore transmission lines: Except for gathering lines exempted from this section in accordance with § 192.9 and offshore transmission lines, after May 24, 2023, whenever an operator discovers any condition that could adversely affect the safe operation of a pipeline segment not covered by an integrity management program under subpart O of this part, it must correct the condition as prescribed in § 192.714.
 - (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.

§ 192.712 Analysis of predicted failure pressure

- (a) *Applicability.* Whenever required by this part, operators of onshore steel transmission pipelines must analyze anomalies or defects to determine the predicted failure pressure at the location of the anomaly or defect, and the remaining life of the pipeline segment at the location of the anomaly or defect, in accordance with this section.
- (b) *Corrosion metal loss.* When analyzing corrosion metal loss under this section, an operator must use a suitable remaining strength calculation method including, ASME/ANSI B31G (incorporated by reference, see § 192.7); R-STRENG (incorporated by reference, see § 192.7); or an alternative equivalent method of remaining strength calculation that will provide an equally conservative result.
 - (1) If an operator would choose to use a remaining strength calculation method that could provide a less conservative result than the methods listed in paragraph (b) introductory text, the operator must notify PHMSA in advance in accordance with § 192.18(c).

- (2) The notification provided for by paragraph (b)(1) of this section must include a comparison of its predicted failure pressures to R-STRENG or ASME/ANSI B31G, all burst pressure tests used, and any other technical reviews used to qualify the calculation method(s) for varying corrosion profiles.
- (c) [Reserved] Dents and other mechanical damage. To evaluate dents and other mechanical damage that could result in a stress riser or other integrity impact, an operator must develop a procedure and perform an engineering critical assessment as follows:
 - (1) Identify and evaluate potential threats to the pipe segment in the vicinity of the anomaly or defect, including ground movement, external loading, fatigue, cracking, and corrosion.
 - (2) Review high-resolution magnetic flux leakage (HR-MFL) high-resolution deformation, inertial mapping, and crack detection inline inspection data for damage in the dent area and any associated weld region, including available data from previous inline inspections.
 - (3) Perform pipeline curvature-based strain analysis using recent HR-Deformation inspection data.
 - (4) Compare the dent profile between the most recent and previous in-line inspections to identify significant changes in dent depth and shape.
 - (5) Identify and quantify all previous and present significant loads acting on the dent.
 - (6) Evaluate the strain level associated with the anomaly or defect and any nearby welds using Finite Element Analysis, or other technology in accordance with this section. Using Finite Element Analysis to quantify the dent strain, and then estimating and evaluating the damage using the Strain Limit Damage (SLD) and Ductile Failure Damage Indicator (DFDI) at the dent, are appropriate evaluation methods.
 - (7) The analyses performed in accordance with this section must account for material property uncertainties, model inaccuracies, and inline inspection tool sizing tolerances.
 - (8) Dents with a depth greater than 10 percent of the pipe outside diameter or with geometric strain levels that exceed the lesser of 10 percent or exceed the critical strain for the pipe material properties must be remediated in accordance with § 192.713, § 192.714, or § 192.933, as applicable.
 - (9) Using operational pressure data, a valid fatigue life prediction model that is appropriate for the pipeline segment, and assuming a reassessment safety factor of 5 or greater for the assessment interval, estimate the fatigue life of the dent by Finite Element Analysis or other analytical technique that is technically appropriate for dent assessment and reassessment intervals in accordance with this section. Multiple dent or other fatigue models must be used for the evaluation as a part of the engineering critical assessment.
 - (10) If the dent or mechanical damage is suspected to have cracks, then a crack growth rate assessment is required to ensure adequate life for the dent with crack(s) until remediation or the dent with crack(s) must be evaluated and remediated in accordance with the criteria and timing requirements in § 192.713, § 192.714, or § 192.933, as applicable.
 - (11) An operator using an engineering critical assessment procedure, other

technologies, or techniques to comply with paragraph (c) of this section must submit advance notification to PHMSA, with the relevant procedures, in accordance with § 192.18.

(d) *Cracks and crack-like defects -*

- (1) *Crack analysis models.* When analyzing cracks and crack-like defects under this section, an operator must determine predicted failure pressure, failure stress pressure, and crack growth using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both), material properties (pipe and weld properties), and boundary condition used (pressure test, ILI, or other).
- ~~(2) *Crack analysis models.* When analyzing cracks and crack-like defects under this section, an operator must determine predicted failure pressure, failure stress pressure, and crack growth using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both), material properties (pipe and weld properties), and boundary condition used (pressure test, ILI, or other).~~
- (2) *Analysis for crack growth and remaining life.* If the pipeline segment is susceptible to cyclic fatigue or other loading conditions that could lead to fatigue crack growth, fatigue analysis must be performed using an applicable fatigue crack growth law (for example, Paris Law) or other technically appropriate engineering methodology. For other degradation processes that can cause crack growth, appropriate engineering analysis must be used. The above methodologies must be validated by a subject matter expert to determine conservative predictions of flaw growth and remaining life at the maximum allowable operating pressure. The operator must calculate the remaining life of the pipeline by determining the amount of time required for the crack to grow to a size that would fail at maximum allowable operating pressure.
 - (i) When calculating crack size that would fail at MAOP, and the material toughness is not documented in traceable, verifiable, and complete records, the same Charpy v-notch toughness value established in paragraph (e)(2) of this section must be used.
 - (ii) Initial and final flaw size must be determined using a fracture mechanics model appropriate to the failure mode (ductile, brittle or both) and boundary condition used (pressure test, ILI, or other).
 - (iii) An operator must re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated by this analysis has expired. The operator must determine and document if further pressure tests or use of other assessment methods are required at that time. The operator must continue to re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated in the most recent evaluation has expired.
- (3) *Cracks that survive pressure testing.* For cases in which the operator does not have in-line inspection crack anomaly data and is analyzing potential crack defects that could have survived a pressure test, the operator must calculate the largest potential crack defect sizes using the methods in paragraph (d)(1) of this section. If pipe material toughness is not documented in traceable, verifiable, and complete records, the operator must use one of the following for Charpy v-notch toughness values based upon minimum operational temperature and equivalent to a full-size specimen value:

- (i) Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;
 - (ii) A conservative Charpy v-notch toughness value to determine the toughness based upon the material properties verification process specified in § 192.607;
 - (iii) A full size equivalent Charpy v-notch upper-shelf toughness level of 120 ft.-lbs.; or
 - (iv) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of the crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in accordance with § 192.18.
- (e) *Data.* In performing the analyses of predicted or assumed anomalies or defects in accordance with this section, an operator must use data as follows.
- (1) An operator must explicitly analyze and account for uncertainties in reported assessment results (including tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance) in identifying and characterizing the type and dimensions of anomalies or defects used in the analyses, unless the defect dimensions have been verified using *in situ* direct measurements.
 - (2) The analyses performed in accordance with this section must utilize pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis is not available, an operator must obtain the undocumented data through § 192.607. Until documented material properties are available, the operator shall use conservative assumptions as follows:
 - (i) *Material toughness.* An operator must use one of the following for material toughness:
 - (A) Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;
 - (B) A conservative Charpy v-notch toughness value to determine the toughness based upon the ongoing material properties verification process specified in § 192.607;
 - (C) If the pipeline segment does not have a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 13.0 ft.- lbs. for body cracks and 4.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion defects;
 - (D) If the pipeline segment has a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 5.0 ft.-lbs. for body cracks and 1.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion; or

- (E) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in advance in accordance with § 192.18 and include in the notification the bases for demonstrating that the Charpy v-notch toughness values proposed are appropriate and conservative for use in analysis of crack-related conditions.
- (ii) *Material strength.* An operator must assume one of the following for material strength:
 - (A) Grade A pipe (30,000 psi), or
 - (B) The specified minimum yield strength that is the basis for the current maximum allowable operating pressure.
- (iii) *Pipe dimensions and other data.* Until pipe wall thickness, diameter, or other data are determined and documented in accordance with § 192.607, the operator must use values upon which the current MAOP is based.
- (f) *Review.* Analyses conducted in accordance with this section must be reviewed and confirmed by a subject matter expert.
- (g) *Records.* An operator must keep for the life of the pipeline records of the investigations, analyses, and other actions taken in accordance with the requirements of this section. Records must document justifications, deviations, and determinations made for the following, as applicable:
 - (1) The technical approach used for the analysis;
 - (2) All data used and analyzed;
 - (3) Pipe and weld properties;
 - (4) Procedures used;
 - (5) Evaluation methodology used;
 - (6) Models used;
 - (7) Direct in situ examination data;
 - (8) In-line inspection tool run information evaluated, including any multiple in-line inspection tool runs;
 - (9) Pressure test data and results;
 - (10) In-the-ditch assessments;
 - (11) All measurement tool, assessment, and evaluation accuracy specifications and tolerances used in technical and operational results;
 - (12) All finite element analysis results;
 - (13) The number of pressure cycles to failure, the equivalent number of annual pressure cycles, and the pressure cycle counting method;
 - (14) The predicted fatigue life and predicted failure pressure from the required fatigue life models and fracture mechanics evaluation methods;
 - (15) Safety factors used for fatigue life and/or predicted failure pressure calculations;

- (16) Reassessment time interval and safety factors;
 - (17) The date of the review;
 - (18) Confirmation of the results by qualified technical subject matter experts; and
 - (19) Approval by responsible operator management personnel.
- (h) Reassessments. If an operator uses an engineering critical assessment method in accordance with paragraphs (c) and (d) of this section to determine the maximum reevaluation intervals, the operator must reassess the anomalies as follows:
- (1) If the anomaly is in an HCA, the operator must reassess the anomaly within a maximum of 7 years in accordance with § 192.939(a), unless the safety factor is expected to go below what is specified in paragraph (c) or (d) of this section.
 - (2) If the anomaly is outside of an HCA, the operator must perform a reassessment of the anomaly within a maximum of 10 years in accordance with § 192.710(b), unless the anomaly safety factor is expected to go below what is specified in paragraph (c) or (d) of this section.

§ 192.713 Transmission Lines: Permanent Field Repair of Imperfections and Damages

- (a) Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be--
 - (1) Removed by cutting out and replacing a cylindrical piece of pipe; or
 - (2) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.
- (b) Operating pressure must be at a safe level during repair operations.

§ 192.714 Transmission lines: Repair criteria for onshore transmission pipelines.

- (a) Applicability. This section applies to onshore transmission pipelines not subject to the repair criteria in subpart O of this part, and which do not operate under an alternative MAOP in accordance with §§ 192.112, 192.328, and 192.620. Pipeline segments that are located in high consequence areas, as defined in § 192.903, must comply with the applicable actions specified by the integrity management requirements in subpart O. Pipeline segments operating under an alternative MAOP in accordance with §§ 192.112, 192.328, and 192.620 must comply with § 192.620(d)(11).
- (b) General. Each operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe manner and are made to prevent damage to persons, property, and the environment. A pipeline segment's operating pressure must be less than the predicted failure pressure determined in accordance with § 192.712 during repair operations. Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis, including predicted failure pressure for determining MAOP, is not available, an operator must obtain the undocumented data through § 192.607. Until documented material properties are available, the operator must use the conservative assumptions in either § 192.712(e)(2) or, if appropriate following a pressure test, in § 192.712(d)(3).
- (c) Schedule for evaluation and remediation. An operator must remediate conditions according to a schedule that prioritizes the conditions for evaluation and remediation. Unless paragraph (d) of this section provides a special requirement for remediating certain

conditions, an operator must calculate the predicted failure pressure of anomalies or defects and follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see § 192.7). If an operator cannot meet the schedule for any condition, the operator must document the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety. Each condition that meets any of the repair criteria in paragraph (d) of this section in an onshore steel transmission pipeline must be—

- (1) Removed by cutting out and replacing a cylindrical piece of pipe that will permanently restore the pipeline's MAOP based on the use of § 192.105 and the design factors for the class location in which it is located; or
 - (2) Repaired by a method, shown by technically proven engineering tests and analyses, that will permanently restore the pipeline's MAOP based upon the determined predicted failure pressure times the design factor for the class location in which it is located.
- (d) Remediation of certain conditions. For onshore transmission pipelines not located in high consequence areas, an operator must remediate a listed condition according to the following criteria:
- (1) Immediate repair conditions. An operator's evaluation and remediation schedule for immediate repair conditions must follow section 7 of ASME/ANSI B31.8S-2004 (incorporated by reference, see § 192.7). An operator must repair the following conditions immediately upon discovery:
 - (i) Metal loss anomalies where a calculation of the remaining strength of the pipe at the location of the anomaly shows a predicted failure pressure, determined in accordance with § 192.712(b), of less than or equal to 1.1 times the MAOP.
 - (ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.
 - (iii) Metal loss greater than 80 percent of nominal wall regardless of dimensions.
 - (iv) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or has a longitudinal joint factor less than 1.0, and the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.25 times the MAOP.
 - (v) A crack or crack-like anomaly meeting any of the following criteria:
 - (A) Crack depth plus any metal loss is greater than 50 percent of pipe wall thickness;
 - (B) Crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth; or

- (C) The crack or crack-like anomaly has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.25 times the MAOP.
- (vi) An indication or anomaly that, in the judgment of the person designated by the operator to evaluate the assessment results, requires immediate action.
- (2) Two-year conditions. An operator must repair the following conditions within 2 years of discovery:
 - (i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.
 - (ii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld, unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.
 - (iii) A dent located between the 4 o'clock and 8 o'clock positions (lower 1/3 of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.
 - (iv) For metal loss anomalies, a calculation of the remaining strength of the pipe shows a predicted failure pressure, determined in accordance with § 192.712(b) at the location of the anomaly, of less than 1.39 times the MAOP for Class 2 locations, or less than 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME/ANSI B31.8S-2004 (incorporated by reference, see § 192.7), section 7, Figure 4, as specified in paragraph (c) of this section.
 - (v) Metal loss that is located at a crossing of another pipeline, is in an area with widespread circumferential corrosion, or could affect a girth weld, and that has a predicted failure pressure, determined in accordance with § 192.712(b), less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.
 - (vi) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0, and where the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been

- updated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.
- (vii) A crack or crack-like anomaly that has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been updated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.
- (3) Monitored conditions. An operator must record and monitor the following conditions during subsequent risk assessments and integrity assessments for any change that may require remediation.
- (i) A dent that is located between the 4 o'clock and 8 o'clock positions (bottom 1/3 of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and where an engineering analysis, performed in accordance with § 192.712(c), demonstrates critical strain levels are not exceeded.
- (ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and where an engineering analysis performed in accordance with § 192.712(c) determines that critical strain levels are not exceeded.
- (iii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal or helical (spiral) seam weld, and where an engineering analysis of the dent and girth or seam weld, performed in accordance with § 192.712(c), demonstrates critical strain levels are not exceeded. These analyses must consider weld mechanical properties.
- (iv) A dent that has metal loss, cracking, or a stress riser, and where an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.
- (v) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been updated in accordance with § 192.611, or is greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.
- (vi) A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been updated in accordance with § 192.611, or is greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

- (e) Temporary pressure reduction.
- (1) Immediately upon discovery and until an operator remediates the condition specified in paragraph (d)(1) of this section, or upon a determination by an operator that it is unable to respond within the time limits for the conditions specified in paragraph (d)(2) of this section, the operator must reduce the operating pressure of the affected pipeline to any one of the following based on safety considerations for the public and operating personnel:
 - (i) A level not exceeding 80 percent of the operating pressure at the time the condition was discovered;
 - (ii) A level not exceeding the predicted failure pressure times the design factor for the class location in which the affected pipeline is located; or
 - (iii) A level not exceeding the predicted failure pressure divided by 1.1.
 - (2) An operator must notify PHMSA in accordance with § 192.18 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) or (d) of this section and cannot provide safety through a temporary reduction in operating pressure or other action. Notification to PHMSA does not alleviate an operator from the evaluation, remediation, or pressure reduction requirements in this section.
 - (3) When a pressure reduction, in accordance with paragraph (e) of this section, exceeds 365 days, an operator must notify PHMSA in accordance with § 192.18 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline.
 - (4) An operator must document and keep records of the calculations and decisions used to determine the reduced operating pressure and the implementation of the actual reduced operating pressure for a period of 5 years after the pipeline has been repaired.
- (f) Other conditions. Unless another timeframe is specified in paragraph (d) of this section, an operator must take appropriate remedial action to correct any condition that could adversely affect the safe operation of a pipeline system in accordance with the criteria, schedules, and methods defined in the operator's operating and maintenance procedures.
- (g) In situ direct examination of crack defects. Whenever an operator finds conditions that require the pipeline to be repaired, in accordance with this section, an operator must perform a direct examination of known locations of cracks or crack-like defects using technology that has been validated to detect tight cracks (equal to or less than 0.008 inches crack opening), such as inverse wave field extrapolation (IWEX), phased array ultrasonic testing (PAUT), ultrasonic testing (UT), or equivalent technology. "In situ" examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection for accuracy of the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations.

- (h) Determining predicted failure pressures and critical strain levels. An operator must perform all determinations of predicted failure pressures and critical strain levels required by this section in accordance with § 192.712.

§ 192.715 Transmission Lines: Permanent Field Repair of Welds

Each weld that is unacceptable under § 192.241(c) must be repaired as follows:

- (a) If it is feasible to take the segment of transmission line out of service, the weld must be repaired in accordance with the applicable requirements of § 192.245.
- (b) A weld may be repaired in accordance with § 192.245 while the segment of transmission line is in service if:
 - (1) The weld is not leaking;
 - (2) The pressure in the segment is reduced so that it does not produce a stress that is more than 20 percent of the SMYS of the pipe; and
 - (3) Grinding of the defective area can be limited so that at least 1/8 inch (3.2 millimeters) thickness in the pipe weld remains.
- (c) A defective weld which cannot be repaired in accordance with paragraph (a) or (b) of this section must be repaired by installing a full encirclement welded split sleeve of appropriate design.

§ 192.717 Transmission Lines: Permanent Field Repair of Leaks

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

- (a) Removing the leak by cutting out and replacing a cylindrical piece of pipe; or
- (b) Repairing the leak by one of the following methods:
 - (1) Install a full encirclement welded split sleeve of appropriate design, unless the transmission line is joined by mechanical couplings and operates at less than 40 percent of SMYS.
 - (2) If the leak is due to a corrosion pit, install a properly designed bolt-on-leak clamp.
 - (3) If the leak is due to a corrosion pit and on pipe of not more than 40,000 p.s.i. (267 MPa) SMYS, fillet weld over the pitted area a steel plate patch with rounded corners, of the same or greater thickness than the pipe, and not more than one-half of the diameter of the pipe in size.
 - (4) If the leak is on a submerged offshore pipeline or submerged pipeline in inland navigable waters, mechanically apply a full encirclement split sleeve of appropriate design.
 - (5) Apply a method that reliable engineering tests and analyses show can permanently

§ 192.719 Transmission Lines: Testing of Repairs

- (a) Testing of replacement pipe. If a segment of transmission line is repaired by cutting out the damaged portion of the pipe as a cylinder, the replacement pipe must be tested to the pressure required for a new line installed in the same location. This test may be made on the pipe before it is installed.
- (b) Testing of repairs made by welding. Each repair made by welding in accordance with §§ 192.713, 192.715, and 192.717 must be examined in accordance with § 192.241.

§192.720 Distribution Systems: Leak Repair

Mechanical leak repair clamps installed after January 22, 2019 may not be used as a permanent repair method for plastic pipe.

§ 192.721 Distribution Systems: Patrolling

- (a) The frequency of patrolling mains must be determined by the severity of the conditions which could cause failure or leakage, and the consequent hazards to public safety.
 - (b) Mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage must be patrolled -
 - (1) In business districts, at intervals not exceeding 4 1/2 months, but at least 4 times each calendar year; and
 - (2) Outside business districts, at intervals not exceeding 7 1/2 months, but at least twice each calendar year
-

§ 192.723 Distribution Systems: Leakage Surveys and Procedures

- (a) Each operator of a distribution system shall conduct periodic leakage surveys in accordance with this section. These surveys must be performed by, or under the direct supervision of, personnel trained and qualified in both the use of appropriate equipment and the classification of leaks. In addition, maps that approximate the location of the mains and transmission lines being surveyed must be available.
- (b) The type and scope of the leakage control program must be determined by the nature of the operations and the local conditions, but it must meet the following minimum requirements.
 - (1) A leakage survey with leak detector equipment shall be conducted in business districts including test of the atmosphere in electric, gas, sewer, telephone, and water system manholes, at cracks in pavement and sidewalks and at other locations providing an opportunity for finding gas leaks. This survey shall be performed with a flame ionization unit or a gas detector at intervals not exceeding 15 months, but at least once each calendar year.
 - (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.
 - (i) A leakage survey of all underground natural gas distribution systems outside of a business district, that are owned/operated or the responsibility of a public or municipal utility shall be performed as frequently as necessary but at intervals not exceeding five (5) calendar years.
 - (ii) A leakage survey of all underground natural gas distribution systems, not owned nor the responsibility of a public or municipal utility and used to transport gas from a master meter or utility company gas main to multiple buildings, shall be performed as frequently as necessary but at intervals not exceeding five (5) years. Owners/operators of these systems shall be responsible to ensure these surveys are accomplished.
- (c) The type and scope of the surveys required in subdivisions (b)(2)(i) and (ii) of this section, must ensure detection, location, evaluation and classification of any gas leakage. The following methods may be employed depending on the design and size of the system or facility:
 - (1) Flame Ionization Detector.
 - (2) Combustible Gas Indicator (includes bar holing).
 - (3) Pressure Drop or No Flow. Only to be used to establish the presence or absence of leakage on a distribution system. Where leakage is indicated, further evaluation by another detection method must be accomplished to locate, evaluate and classify leaks. When this method is used to verify no leakage exists a test record certified by a qualified person, organization or agency must be retained with records of survey.

NOTE: *Test duration must be of sufficient length to detect leakage, and the following should be considered:*

Volume under test and the time for the test medium to become temperature stabilized.

- (d) All leaks detected shall be classified to assure a standardized priority of repair is established. There is no precise means presently developed to accurately classify leaks, however, there are four general categories that must be considered when judging the severity of gas leaks:
- (1) Proportion. The quantity of gas escaping based on gas indicator readings, pressure of line or container from which gas is escaping and concentration of odor.
 - (2) Location. The centralized location of escaping gas; under buildings and paved surfaces, near occupied buildings, near source of ignition or in open areas where the concentration of gas is improbable.
 - (3) Dispersion. The areas to which escaping gas may spread. Based on depth of line, type of soil, pressure, surface cover, moisture, frozen soil and other soil conditions.
 - (4) Evaluation. All factors must be evaluated, applying experience and good judgment in arriving at the proper classification.
- (e) To standardize leak classification, using the above factors, all leaks shall be classified in the following categories:
- (1) Class 1. Leaks that represent an existing or probable hazard to persons or property and requires immediate repair or continuous action until the hazardous condition no longer exists.
 - (2) Class 2. Leaks that are considered non-hazardous at the time of detection, but could become hazardous if repair is not accomplished in a reasonable length of time. Repair as soon as possible, but within a period not to exceed five months.
 - (3) Class 3. Leaks that are non-hazardous at the time of detection and can be expected to remain non-hazardous. These leaks should be re-evaluated during the next scheduled survey. Repair as time and expenditures permit.
- (f)
- (1) In addition to leak surveys, any leak or gas odor reported from the public, fire, police or other authorities or notification of damage to facilities by outside sources shall require prompt investigation. Thorough investigations shall be performed on all suspected leaks to determine the degree of existing hazard to person or property. This includes entering structures in a reported or suspected leakage area and checking for presence of gas.
 - (2) Leaks reported on customer's piping shall be investigated by trained and qualified employees who must judge the degree of hazard and establish the required repair priority. If a hazardous leak exists on customer's piping, the service shall be immediately terminated upstream of the leak. If the leak is not presently hazardous but may become hazardous, the customer shall be given a reasonable time to repair the leak.
- (g) A leak repair record shall be made for every leak detected or identified. Leaks discovered on customer's piping, downstream of the meter, shall be documented on operator's service orders and retained until the customer's piping has been repaired to the satisfaction of the operator. Corrosion leaks shall be documented on permanent records and shall be retained for as long as the segment of pipeline on which the leak was located is in service. As a minimum, leak records other than corrosion shall be maintained on the two most current leak surveys. Each leak record shall contain, as a minimum, the following:

- (1) Date leak discovered.
 - (2) Location.
 - (3) Classification.
 - (4) Cause of leak.
 - (5) Unique identifier for person making the repair or responsible for maintaining the records of work accomplished.
- (h) Leaks may be reclassified by responsible and suitable experienced persons whose name shall appear on the documents.

§ 192.724 Hazardous Facilities

- (a) If at any time the supplier to a master meter system or private line system becomes aware that the receiving system is experiencing a lost and unaccounted for gas percentage of ten percent (10%) or more, as calculated on a rolling average over the prior year, the supplier may terminate service to the receiving system without delay.
- (b) If at any time the supplier to a master meter system or private line system becomes aware that the receiving system has an operating condition which causes it to deliver gas service in an unsafe manner and endanger life or property, the supplier shall terminate service to the receiving system without delay.
- (c) Following the termination of service pursuant to (a) or (b) above, the supplier to a master meter system or private line system shall make contact with PSO personnel by telephone or electronic mail within one hour of termination and provide a detailed justification for such termination.
- (d) Prior to reconnection of service to a master meter system or private line system that has been terminated pursuant to (a) or (b) above, the supplier shall comply with its reconnection policy.

§ 192.725 Test Requirements for Reinstating Service Lines

- (a) Except as provided in paragraph (b) of this section, each disconnected service line must be tested in the same manner as a new service line, before being reinstated.
- (b) Each service line temporarily disconnected from the main must be tested from the point of disconnection to the service line valve in the same manner as a new service line, before reconnecting. However, if provisions are made to maintain continuous service, such as installation of a bypass, any part of the original service line used to maintain continuous service need not be tested.

§ 192.727 Abandonment or Deactivation of Facilities

- (a) Each operator shall conduct abandonment or deactivation of pipelines in accordance with the requirements of this section.
- (b) Each pipeline abandoned in place must be disconnected from all sources and supplies of gas, purged of gas, and the ends sealed. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.
- (c) Except for service lines, each inactive pipeline that is not being maintained under this part must be disconnected from all sources and supplies of gas, purged of gas, and the ends sealed. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

- (d) Whenever service to a customer is discontinued, one of the following must be complied with:
- (1) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.
 - (2) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.
 - (3) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.
- (e) If air is used for purging, the operator shall ensure that a combustible mixture is not present after purging.
- (f) Each abandoned vault must be filled with a suitable compacted material.
- (g) For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility
- (1) ~~The preferred method to submit data on pipeline facilities abandoned after October 10, 2000 is to the National Pipeline Mapping System (NPMS) in accordance with the NPMS for Pipeline and Liquefied Natural Gas Operator. To obtain a copy of the NPMS Standards, please refer to the NPMS homepage at <http://www.npms.phmsa.dot.gov> or contact the NPMS National Repository at 703-317-3073. A digital data format is preferred, but hard copy submissions are acceptable if they comply with the NPMS Standards. In addition to the NPMS-required attributes, operators must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the knowledge, all of the reasonably available information requested was provided and, to the best of the knowledge, the abandonment was completed in accordance with applicable laws. Refer to the NPMS Standards for details in preparing your data for submission. The NPMS Standards also include details of how to submit data. Alternatively, operators may submit reports by mail, fax or e-mail to the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP-10, 1200 New Jersey Avenue, SE., Washington, DC 20590-0001; fax (202) 366-4566; e-mail InformationResourcesManager@phmsa.dot.gov. The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws. The preferred method to submit data on pipeline facilities abandoned after October 10, 2000, is to the National Pipeline Mapping System (NPMS) in accordance with the NPMS "Standards for Pipeline and Liquefied Natural Gas Operator Submissions." To obtain a copy of the NPMS Standards, please refer to the NPMS homepage at www.npms.phmsa.dot.gov. A digital data format is preferred, but hard copy submissions are acceptable if they comply with the NPMS Standards. In addition to the NPMS-required attributes, operators must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the operator's knowledge, all of the reasonably available information requested was provided and, to the best of the operator's knowledge, the abandonment was completed in accordance with applicable laws. Refer to the NPMS Standards for details in~~

preparing your data for submission. The NPMS Standards also include details of how to submit data. Alternatively, operators may submit reports by mail, fax or email to the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP-10, 1200 New Jersey Avenue SE, Washington, DC 20590-0001; fax (202) 366-4566; email InformationResourcesManager@dot.gov. The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws.

(2) [Reserved].

§ 192.731 Compressor Stations: Inspection and Testing of Relief Devices

- (a) Except for rupture discs, each pressure relieving device in a compressor station must be inspected and tested in accordance with §§ 192.739 and 192.743, and must be operated periodically to determine that it opens at the correct set pressure.
- (b) Any defective or inadequate equipment found must be promptly repaired or replaced.
- (c) Each remote control shutdown device must be inspected and tested, at intervals not exceeding 15 months, but at least once each calendar year, to determine that it functions properly.

§ 192.735 Compressor Stations: Storage of Combustible Materials

- (a) Flammable or combustible materials in quantities beyond those required for everyday use, or other than those normally used in compressor buildings, must be stored a safe distance from the compressor building.
- (b) Above-ground oil or gasoline storage tanks must be protected in accordance with NFPA-30 (incorporated by reference, see § 192.7).

§ 192.736 Compressor Stations: Gas Detection

- (a) Not later than September 16, 1996, each compressor building in a compressor station must have a fixed gas detection and alarm system, unless the building is:
 - (1) Constructed so that at least 50 percent of its upright side area is permanently open; or
 - (2) Located in an unattended field compressor station of 1,000 horsepower (746 kW) or less.
- (b) Except when shutdown of the system is necessary for maintenance under paragraph (c) of this section, each gas detection and alarm system required by this section must:
 - (1) Continuously monitor the compressor building for a concentration of gas in air of not more than 25 percent of the lower explosive limit; and
 - (2) If that concentration of gas is detected, warn persons about to enter the building and persons inside the building of the danger.
- (c) Each gas detection and alarm system required by this section must be maintained to function properly. The maintenance must include performance tests.

§ 192.739 Pressure Limiting and Regulating Stations: Inspection and Testing

- (a) Each pressure limiting station, relief device (except rupture discs), and pressure

regulating station and its equipment must be subjected, at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests. These inspections and tests shall include the following:

- (1) Pressure regulating devices.
 - (i) Each regulator must be inspected to ensure it is in good working order, controls pressure and capacity within acceptable limits for the system in which it is installed.
 - (ii) Shuts off pressure within acceptable limits.
 - (iii) Second stage regulator will withstand and control first stage inlet pressure if a relief valve is not installed between regulators.
 - (iv) Properly installed control lines, controllers, actuators and protected from conditions that may prevent proper operation.
 - (v) Except as provided in paragraph (b) of this section, set to control or relieve at the correct pressure consistent with the pressure limits of § 192.201(a); and
 - (2) Pressure limiting and relief devices.
 - (i) Monitor regulators tested for proper operating parameters.
 - (ii) Except as provided in paragraph (b) of this section set to control or relieve at the correct pressure consistent with the pressure limits of § 192.201 (a); and
 - (iii) Vent stacks are free of obstructions, properly routed, vented outside of building and vents adequately covered.
 - (iv) Block valves connecting relief devices to a system shall be locked in the open position and block valves in manually-fed above ground bypasses shall be locked in the closed position.
- (b) For steel pipelines whose MAOP is determined under § 192.619(c), if the MAOP is 60 p.s.i. (414 kPa) gage or more, the control or relief pressure limit is as follows:

If the MAOP produces a hoop stress that is:	Then the pressure limit is:
Greater than 72 percent of SMYS	MAOP plus 4 percent
Unknown as a percentage of SMYS	A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP

§ 192.740 Pressure regulating, limiting, and overpressure protection--Individual service lines directly connected to regulated gathering or transmission pipelines

- (a) This section applies, except as provided in paragraph (c) of this section, to any service line directly connected to a transmission pipeline or regulated gathering pipeline as determined in §192.8 that is not operated as part of a distribution system.
- (b) Each pressure regulating or limiting device, relief device (except rupture discs), automatic shutoff device, and associated equipment must be inspected and tested at least

once every 3 calendar years, not exceeding 39 months, to determine that it is:

- (1) In good mechanical condition;
 - (2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;
 - (3) Set to control or relieve at the correct pressure consistent with the pressure limits of § 192.197; and to limit the pressure on the inlet of the service regulator to 60 psi (414 kPA) gauge or less in case the upstream regulator fails to function properly; and
 - (4) Properly installed and protected from dirt, liquids, or conditions that might prevent proper operation.
- (c) This section does not apply to equipment installed on:
- (1) A service line that only serves engines that power irrigation pumps;
 - (2) A service line included in a distribution integrity management plan meeting the requirements of subpart P of this part; or
 - (3) A service line directly connected to either a production or gathering pipeline other than a regulated gathering line as determined in §192.8 of this part.

§ 192.741 Pressure Limiting and Regulating Stations: Telemetry or Recording Gauges

- (a) Each distribution system supplied by more than one district pressure regulating station must be equipped with telemetry or recording pressure gauges to indicate the gas pressure in the district.
- (b) On distribution systems supplied by a single district pressure regulating station, the operator shall determine the necessity of installing telemetry or recording gauges in the district, taking into consideration the number of customers supplied, the operating pressures, the capacity of the installation, and other operating conditions.
- (c) If there are indications of abnormally high or low pressure, the regulator and the auxiliary equipment must be inspected and the necessary measures employed to correct any unsatisfactory operating conditions.

§ 192.743 Pressure Limiting and Regulating Stations: Capacity of Relief Devices

- (a) Pressure relief devices at pressure limiting stations and pressure regulating stations must have sufficient capacity to protect the facilities to which they are connected. Except as provided in § 192.739(b), the capacity must be consistent with the pressure limits of § 192.201(a). This capacity must be determined at intervals not exceeding 15 months, but at least once each calendar year, by testing the devices in place or by review and calculations.
- (b) If review and calculations are used to determine if a device has sufficient capacity, the calculated capacity must be compared with the rated or experimentally determined relieving capacity of the device for the conditions under which it operates. After the initial calculations, subsequent calculations need not be made if the annual review documents that parameters have not changed to cause the rated or experimentally determined relieving capacity to be insufficient.
- (c) If a relief device is of insufficient capacity, a new or additional device must be installed to provide the capacity required by paragraph (a) of this section.

§ 192.745 Valve Maintenance: Transmission Lines

- (a) Each valve, the use of which may be necessary for the safe operation of a transmission line, must be identified and readily accessible. These valves must be inspected, lubricated when necessary and partially operated at intervals not exceeding 15 months, but at least once each calendar year.
- (b) Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.
- (c) For each remote-control valve (RCV) installed in accordance with § 192.179 or § 192.634, an operator must conduct a point-to-point verification between SCADA system displays and the installed valves, sensors, and communications equipment, in accordance with § 192.631(c) and (e).
- (d) For each alternative equivalent technology installed on an onshore pipeline under § 192.179(e) or (f) or § 192.634 that is manually or locally operated (i.e., not a rupture-mitigation valve (RMV), as that term is defined in § 192.3):
 - (1) Operators must achieve a valve closure time of 30 minutes or less, pursuant to § 192.636(b), through an initial drill and through periodic validation as required in paragraph (d)(2) of this section. An operator must review and document the results of each phase of the drill response to validate the total response time, including confirming the rupture, and valve shut-off time as being less than or equal to 30 minutes after rupture identification.
 - (2) Within each pipeline system and within each operating or maintenance field work unit, operators must randomly select a valve serving as an alternative equivalent technology in lieu of an RMV for an annual 30-minute-total response time validation drill that simulates worst-case conditions for that location to ensure compliance with § 192.636. Operators are not required to close the valve fully during the drill; a minimum 25 percent valve closure is sufficient to demonstrate compliance with drill requirements unless the operator has operational information that requires an additional closure percentage for maintaining reliability. The response drill must occur at least once each calendar year, with intervals not to exceed 15 months. Operators must include in their written procedures the method they use to randomly select which alternative equivalent technology is tested in accordance with this paragraph.
 - (3) If the 30-minute-maximum response time cannot be achieved during the drill, the operator must revise response efforts to achieve compliance with § 192.636 as soon as practicable but no later than 12 months after the drill. Alternative valve shut-off measures must be in place in accordance with paragraph (e) of this section within 7 days of a failed drill.
 - (4) Based on the results of response-time drills, the operator must include lessons learned in:
 - (i) Training and qualifications programs;
 - (ii) Design, construction, testing, maintenance, operating, and emergency

procedures manuals; and

(iii) Any other areas identified by the operator as needing improvement.

(5) The requirements of this paragraph (d) do not apply to manual valves who, pursuant to § 192.636(g), have been exempted from the requirements of § 192.636(b).

(e) Each operator must develop and implement remedial measures to correct any valve installed on an onshore pipeline under § 192.179(e) or (f) or § 192.634 that is indicated to be inoperable or unable to maintain effective shut-off as follows:

a. Repair or replace the valve as soon as practicable but no later than 12 months after finding that the valve is inoperable or unable to maintain effective shut-off. An operator must request an extension from PHMSA in accordance with § 192.18 if repair or replacement of a valve within 12 months would be economically, technically, or operationally infeasible; and

b. Designate an alternative valve acting as an RMV within 7 calendar days of the finding while repairs are being made and document an interim response plan to maintain safety. Such valves are not required to comply with the valve spacing requirements of this part.

(f) An operator using an ASV as an RMV, in accordance with §§ 192.3, 192.179, 192.634, and 192.636, must document and confirm the ASV shut-in pressures, in accordance with § 192.636(f), on a calendar year basis not to exceed 15 months. ASV shut-in set pressures must be proven and reset individually at each ASV, as required, on a calendar year basis not to exceed 15 months.

§ 192.747 Valve Maintenance: Distribution Systems

(a) Each valve, the use of which may be necessary for the safe operation of a distribution system must be identified and readily accessible. These valves must be inspected, lubricated when necessary and partially operated at intervals not exceeding 15 months, but at least once each calendar year.

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

§ 192.749 Vault Maintenance

(a) Each vault housing pressure regulating and pressure limiting equipment and having a volumetric internal content of 200 cubic feet (5.66 cubic meters) or more, must be inspected, at intervals not exceeding 15 months, but at least once each calendar year, to determine that it is in good physical condition and adequately ventilated.

(b) If gas is found in the vault, the equipment in the vault must be inspected for leaks, and any leaks found must be repaired.

(c) The ventilating equipment must also be inspected to determine that it is functioning properly.

- (d) Each vault cover must be inspected to assure that it does not present a hazard to public safety.

§ 192.750 Launcher and receiver safety

Any launcher or receiver used after July 1, 2021, must be equipped with a device capable of safely relieving pressure in the barrel before removal or opening of the launcher or receiver barrel closure or flange and insertion or removal of in-line inspection tools, scrapers, or spheres. An operator must use a device to either: Indicate that pressure has been relieved in the barrel; or alternatively prevent opening of the barrel closure or flange when pressurized, or insertion or removal of in-line devices (e.g. inspection tools, scrapers, or spheres), if pressure has not been relieved.

§ 192.751 Prevention of Accidental Ignition

Each operator shall take steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion, including the following:

- (a) When a hazardous amount of gas is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be provided.
- (b) Gas or electric welding or cutting may not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work.
- (c) Post warning signs, where appropriate.

§ 192.753 Caulked Bell and Spigot Joints

- (a) Each cast iron caulked bell and spigot joint that is subject to pressures of more than 25 p.s.i. (172kPa) gage must be sealed with:
 - (1) A mechanical leak clamp; or
 - (2) A material or device which:
 - (i) Does not reduce flexibility of the joint;
 - (ii) Permanently bonds, either chemically or mechanically, or both, with the bell and spigot metal surfaces or adjacent pipe metal surfaces; and
 - (iii) Seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements of §§ 192.53(a) and (b) and § 192.143.
- (b) Each cast iron caulked bell and spigot joint that is subject to pressures of 25 p.s.i. (172kPa) gage or less and is exposed for any reason must be sealed by a means other than caulking.

§ 192.755 Protecting Cast Iron Pipelines

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

- (a) That segment of the pipeline must be protected, as necessary, against damage during the disturbance by:
 - (1) Vibrations from heavy construction equipment, trains, trucks, buses or blasting;
 - (2) Impact force by vehicles;
 - (3) Earth movement;
 - (4) Apparent future excavations near the pipeline; or

- (5) Other foreseeable outside forces which may subject that segment of the pipeline to bending stress.
- (b) As soon as feasible, appropriate steps must be taken to provide permanent protection for the disturbed segment from damage that might result from external loads, including compliance with applicable requirements of §§ 192.317(a), 192.319, and 192.361(b) - (d).

§192.756 Joining plastic pipe by heat fusion; equipment maintenance and calibration

Each operator must maintain equipment used in joining plastic pipe in accordance with the manufacturer's recommended practices or with written procedures that have been proven by test and experience to produce acceptable joints.

SUBPART N - QUALIFICATION OF PIPELINE PERSONNEL

§ 192.801 Scope

- (a) This subpart prescribes the minimum requirements for operator qualification of individuals performing covered tasks on a pipeline facility.
- (b) For the purpose of this subpart, a covered task is an activity, identified by the operator, that:
 - (1) Is performed on a pipeline facility;
 - (2) Is an operations or maintenance task;
 - (3) Is performed as a requirement of this part; and
 - (4) Affects the operation or integrity of the pipeline.

§ 192.803 Definitions

Abnormal operating condition means a condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:

- (a) Indicate a condition exceeding design limits; or
- (b) Result in a hazard(s) to persons, property, or the environment.

Evaluation means a process, established and documented by the operator, to determine an individual's ability to perform a covered task by any of the following:

- (a) Written examination;
- (b) Oral examination;
- (c) Work performance history review;
- (d) Observation during:
 - (1) Performance on the job,
 - (2) On the job training, or
 - (3) Simulations;
- (e) Other forms of assessment.

Qualified means:

- (1) For an operator defined in § 192.3(1), that an individual can:

(a) Perform assigned, covered tasks, and

(b) Recognize and react to abnormal operating conditions.

(1)(2) For an operator defined in § 192.3(2), that an individual has been evaluated-certified by a training program or institution accredited by the International Accreditors for Continuing Education and Training or other similar accreditation institution, that the individual and can:

(a) Perform assigned, covered tasks; and

(b) Recognize and react to abnormal operating conditions.

§ 192.805 Qualification Program

Each operator shall have and follow a written qualification program. The program shall include provisions to:

- (a) Identify covered tasks;
- (b) Ensure ~~through evaluation~~ that individuals performing covered tasks are qualified;
- (c) Allow individuals that are not qualified ~~pursuant to this subpart~~ to perform a covered task if directed and observed by an individual that is qualified;
- (d) Evaluate whether an individual's performance of a covered task contributed to an incident as defined in Part 191; if the operator has reason to believe that the individual's performance of a covered task contributed to an incident as defined in Part 191;
- (e) ~~Evaluate an individual if the operator has reason to believe that the~~Determine whether an individual is no longer qualified to perform a covered task and needs to be requalified;
- (f) Communicate changes that affect covered tasks to individuals performing those covered tasks;
- (g) ~~Identify these~~Determine the requalification intervals for covered tasks ~~and the intervals at which evaluation of the individual's qualifications is needed;~~
- (h) After December 16, 2004, ~~provide training, as appropriate, to~~ ensure the safe operation of pipeline facilities, operators must ensure that individuals performing covered tasks are qualified and have the necessary ability and skills to perform the covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities; and
- (i) After December 16, 2004, notify the Administrator or a state agency participating under 49 U.S.C. Chapter 601 within 20 days if the operator significantly modifies the program after the Administrator or state agency has verified that it complies with this section. Notifications to PHMSA must be submitted in accordance with § 192.18.

§ 192.807 Recordkeeping

Each operator shall maintain records that demonstrate compliance with this subpart.

- (a) Qualification records shall include:
 - (1) Identification of qualified individual(s);
 - (2) Identification of the covered tasks the individual is qualified to perform;
 - (3) Date(s) of current qualification; and
 - (4) Qualification method(s).

- (b) Records supporting an individual's current qualification shall be maintained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of five years.

§ 192.809 General

- (a) Operators must have a written qualification program by April 27, 2001. The program must be available for review by the Administrator or by a state agency participating under 49 U.S.C. Chapter 601 if the program is under the authority of that state agency.
- (b) Operators must complete the qualification of individuals performing covered tasks by October 28, 2002.
- (c) Work performance history review may be used as a sole evaluation method for individuals who were performing a covered task prior to October 26, 1999.
- (d) After October 28, 2002, work performance history may not be used as a sole evaluation method.
- (e) After December 16, 2004 observation of on-the-job performance may not be used as the sole method of evaluation.

SUBPART O – GAS TRANSMISSION PIPELINE INTEGRITY MANAGEMENT

§ 192.901 What do the regulations in this subpart cover?

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

§ 192.903 What definitions apply to this subpart?

The following definitions apply to this subpart:

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

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

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

Direct assessment is an integrity assessment method that utilizes a process to evaluate certain threats (*i.e.*, external corrosion, internal corrosion and stress corrosion cracking) to a covered pipeline segment's integrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.

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

- (a) An area defined as
 - (i) A Class 3 location under § 192.5; or
 - (ii) A Class 4 location under § 192.5; or
 - (iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or
 - (iv) Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site.
- (b) The area within a potential impact circle containing--
 - (i) 20 or more buildings intended for human occupancy, unless the exception in paragraph (4) applies; or
 - (ii) An identified site.
- (c) Where a potential impact circle is calculated under either method (1) or (2) to establish a high consequence area, the length of the high consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more

buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy. (See Figure E.I.A. in Appendix E.)

- (d) If in identifying a high consequence area under paragraph (1)(iii) of this definition or paragraph (2)(i) of this definition, the radius of the potential impact circle is greater than 660 feet (200 meters), the operator may identify a high consequence area based on a prorated number of buildings intended for human occupancy within a distance 660 feet (200 meters) from the centerline of the pipeline until December 17, 2006. If an operator chooses this approach, the operator must prorate the number of buildings intended for human occupancy based on the ratio of an area with a radius of 660 feet (200 meters) to the area of the potential impact circle (*i.e.*, the prorated number of buildings intended for human occupancy is equal to $20 \times (660 \text{ feet})$ [or 200 meters] / (potential impact radius in feet [or meters]²).

Identified site means each of the following areas:

- (a) An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive). Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or
- (b) A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. (The days and weeks need not be consecutive). Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks; or
- (c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.

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

Potential impact radius (PIR) means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula $r = 0.69 * (\text{square root of } (p*d^2))$, where 'r' is the radius of a circular area in feet surrounding the point of failure, 'p' is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and 'd' is the nominal diameter of the pipeline in inches.

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

Remediation is a repair or mitigation activity an operator takes on a covered segment to limit or reduce the probability of an undesired event occurring or the expected consequences from the event.

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

- (a) *General.* To determine which segments of an operator's transmission pipeline system

are covered by this subpart, an operator must identify the high consequence areas. An operator must use method (1) or (2) from the definition in § 192.903 to identify a high consequence area. An operator may apply one method to its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system. An operator must describe in its integrity management program which method it is applying to each portion of the operator's pipeline system. The description must include the potential impact radius when utilized to establish a high consequence area. (See Appendix E.I. for guidance on identifying high consequence areas.)

- (b)(1) *Identified sites.* An operator must identify an identified site, for purposes of this subpart, from information the operator has obtained from routine operation and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate to the operator that they know of locations that meet the identified site criteria. These public officials could include officials on a local emergency planning commission or relevant Native American tribal officials.
- (2) If a public official with safety or emergency response or planning responsibilities informs an operator that it does not have the information to identify an identified site, the operator must use one of the following sources, as appropriate, to identify these sites.
- (i) Visible marking (e.g., a sign); or
 - (ii) The site is licensed or registered by a Federal, State, or local government agency; or
 - (iii) The site is on a list (including a list on an internet web site) or map maintained by or available from a Federal, State, or local government agency and available to the general public.
- (c) *Newly-identified areas.* When an operator has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions in § 192.903, the operator must complete the evaluation using method (1) or (2). If the segment is determined to meet the definition as a high consequence area, it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified.

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

- (a) *General.* No later than December 17, 2004, an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in § 192.911 and that addresses the risks on each covered transmission pipeline segment. The initial integrity management program must consist, at a minimum, of a framework that describes the process for implementing each program element, how relevant decisions will be made and by whom, a time line for completing the work to implement the program element, and how information gained from experience will be continuously incorporated into the program. The framework will evolve into a more detailed and comprehensive program. An operator must make continual improvements to the program.
- (b) *Implementation Standards.* In carrying out this subpart, an operator must follow the requirements of this subpart and of ASME/ANSI B31.8S (incorporated by reference, see § 192.7) and its appendices, where specified. An operator may follow an equivalent standard or practice only when the operator demonstrates the alternative standard or practice provides an equivalent level of safety to the public and property. In the event

of a conflict between this subpart and ASME/~~ANSI~~ B31.8S, the requirements in this subpart control.

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

- (a) *General.* An operator must document any change to its program and the reasons for the change before implementing the change.
- (b) *Notification.* An operator must notify OPS, in accordance with § 192.18, of any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. An operator must provide notification within 30 days after adopting this type of change into its program.

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

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

- (a) An identification of all high consequence areas, in accordance with § 192.905.
- (b) A baseline assessment plan meeting the requirements of §§ 192.919 and 192.921.
- (c) An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (§ 192.917) and to evaluate the merits of additional preventive and mitigative measures (§ 192.935) for each covered segment.
- (d) A direct assessment plan, if applicable, meeting the requirements of § 192.923, and depending on the threat assessed, of §§ 192.925, 192.927, or 192.929.
- (e) Provisions meeting the requirements of § 192.933 for remediating conditions found during an integrity assessment.
- (f) A process for continual evaluation and assessment meeting the requirements of § 192.937.
- (g) If applicable, a plan for confirmatory direct assessment meeting the requirements of § 192.931.
- (h) Provisions meeting the requirements of § 192.935 for adding preventive and mitigative measures to protect the high consequence area.
- (i) A performance plan as outlined in ASME/~~ANSI~~ B31.8S, section 9 that includes performance measures meeting the requirements of § 192.945.
- (j) Record keeping provisions meeting the requirements of § 192.947.
- (k) ~~A management of change process as outlined in ASME/ANSI B31.8S, section 11. A~~
management of change process as required by § 192.13(d).
- (l) A quality assurance process as outlined in ASME/~~ANSI~~ B31.8S, section 12.
- (m) A communication plan that includes the elements of ASME/~~ANSI~~ B31.8S, ~~section 10-~~
Paragraph 850.9 (incorporated by reference, see § 192.7), and that includes procedures for addressing safety concerns raised by:
 - (1) OPS; and
 - (2) A State or local pipeline safety authority when a covered segment is located in

- a State where OPS has an interstate agent agreement.
- (n) Procedures for providing (when requested), by electronic or other means, a copy of the operator's risk analysis or integrity management program to:
 - (1) OPS; and
 - (2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.
- (o) Procedures for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks.
- (p) A process for identification and assessment of newly-identified high consequence areas. (See § 192.905 and § 192.921.)

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

- (a) *General.* ASME/ANSI B31.8S (incorporated by reference, see § 192.7) provides the essential features of a performance-based or a prescriptive integrity management program. An operator that uses a performance-based approach that satisfies the requirements for exceptional performance in paragraph (b) of this section may deviate from certain requirements in this subpart, as provided in paragraph (c) of this section.
- (b) *Exceptional performance.* An operator must be able to demonstrate the exceptional performance of its integrity management program through the following actions.
 - (1) To deviate from any of the requirements set forth in paragraph (c) of this section, an operator must have a performance-based integrity management program that meets or exceed the performance-based requirements of ASME/ANSI B31.8S and includes, at a minimum, the following elements:
 - (i) A comprehensive process for risk analysis;
 - (ii) All risk factor data used to support the program;
 - (iii) A comprehensive data integration process;
 - (iv) A procedure for applying lessons learned from assessment of covered pipeline segments to pipeline segments not covered by this subpart;
 - (v) A procedure for evaluating every incident, including its cause, within the operator's sector of the pipeline industry for implications both to the operator's pipeline system and to the operator's integrity management program;
 - (vi) A performance matrix that demonstrates the program has been effective in ensuring the integrity of the covered segments by controlling the identified threats to the covered segments;
 - (vii) Semi-annual performance measures beyond those required in § 192.945 that are part of the operator's performance plan. (See § 192.911(i).) An operator must submit these measures, by electronic or other means, on a semi-annual frequency to OPS in accordance with § 192.951; and
 - (viii) An analysis that supports the desired integrity reassessment interval and the remediation methods to be used for all covered segments.
 - (2) In addition to the requirements for the performance-based plan, an operator must:

- (i) Have completed at least two integrity assessments on each covered pipeline segment the operator is including under the performance-based approach, and be able to demonstrate that each assessment effectively addressed the identified threats on the covered segment.
 - (ii) Remediate all anomalies identified in the more recent assessment according to the requirements in § 192.933, and incorporate the results and lessons learned from the more recent assessment into the operator's data integration and risk assessment.
- (c) *Deviation.* Once an operator has demonstrated that it has satisfied the requirements of paragraph (b) of this section, the operator may deviate from the prescriptive requirements of ASME/ANSI B31.8S and of this subpart only in the following instances.
- (1) The time frame for reassessment as provided in § 192.939 except that reassessment by some method allowed under this subpart (e.g., confirmatory direct assessment) must be carried out at intervals no longer than seven years;
 - (2) The time frame for remediation as provided in § 192.933 if the operator demonstrates the time frame will not jeopardize the safety of the covered segment.

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

- (a) *Supervisory personnel.* The integrity management program must provide that each supervisor whose responsibilities relate to the integrity management program possesses and maintains a thorough knowledge of the integrity management program and of the elements for which the supervisor is responsible. The program must provide that any person who qualifies as a supervisor for the integrity management program has appropriate training or experience in the area for which the person is responsible.
- (b) *Persons who carry out assessments and evaluate assessment results.* The integrity management program must provide criteria for the qualification of any person
 - (1) Who conducts an integrity assessment allowed under this subpart; or
 - (2) Who reviews and analyzes the results from an integrity assessment and evaluation; or
 - (3) Who makes decisions on actions to be taken based on these assessments.
- (c) *Persons responsible for preventive and mitigative measures.* The integrity management program must provide criteria for the qualification of any person:
 - (1) Who implements preventive and mitigative measures to carry out this subpart, including the marking and locating of buried structures; or
 - (2) Who directly supervises excavation work carried out in conjunction with an integrity assessment.

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

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

- corrosion cracking;
- (2) ~~Static or resident threats, such as fabrication or construction defects; Stable threats, such as manufacturing, welding, fabrication, or construction defects;~~
 - (3) Time independent threats such as third party damage, mechanical damage, incorrect operational procedure, weather related and outside force damage to include consideration of seismicity, geology, and soil stability of the area; and
 - (4) Human error, such as operational or maintenance mishaps, or design and construction mistakes.
- (b) *Data gathering and integration.* To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/~~ANSI~~ B31.8S, section 4. ~~At a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline. An operator may request an extension of up to 1 year by submitting a notification to PHMSA at least 90 days before February 26, 2024, in accordance with § 192.18. The notification must include a reasonable and technically justified basis, an up-to-date plan for completing all actions required by this paragraph (b), the reason for the requested extension, current safety or mitigation status of the pipeline segment, the proposed completion date, and any needed temporary safety measures to mitigate the impact on safety. An operator must gather and evaluate the set of data listed in paragraph (b)(1) of this section. The evaluation must analyze both the covered segment and similar non-covered segments, and it must:~~
- (1) Integrate pertinent information about pipeline attributes to ensure safe operation and pipeline integrity, including information derived from operations and maintenance activities required under this part, and other relevant information, including, but not limited to:
 - (i) Pipe diameter, wall thickness, seam type, and joint factor;
 - (ii) Manufacturer and manufacturing date, including manufacturing data and records;
 - (iii) Material properties including, but not limited to, grade, specified minimum yield strength (SMYS), and ultimate tensile strength;
 - (iv) Equipment properties;
 - (v) Year of installation;
 - (vi) Bending method;
 - (vii) Joining method, including process and inspection results;
 - (viii) Depth of cover;
 - (ix) Crossings, casings (including if shorted), and locations of foreign line crossings and nearby high voltage power lines;
 - (x) Hydrostatic or other pressure test history, including test pressures and test leaks or failures, failure causes, and repairs;

- (xi) Pipe coating methods (both manufactured and field applied), including the method or process used to apply girth weld coating, inspection reports, and coating repairs;
- (xii) Soil, backfill;
- (xiii) Construction inspection reports, including but not limited to:
 - (A) Post backfill coating surveys; and
 - (B) Coating inspection (“jeeping” or “holiday inspection”) reports;
- (xiv) Cathodic protection installed, including, but not limited to, type and location;
- (xv) Coating type;
- (xvi) Gas quality;
- (xvii) Flow rate;
- (xviii) Normal maximum and minimum operating pressures, including maximum allowable operating pressure (MAOP);
- (xix) Class location;
- (xx) Leak and failure history, including any in-service ruptures or leaks from incident reports, abnormal operations, safety-related conditions (both reported and unreported) and failure investigations required by § 192.617, and their identified causes and consequences;
- (xxi) Coating condition;
- (xxii) Cathodic protection (CP) system performance;
- (xxiii) Pipe wall temperature;
- (xxiv) Pipe operational and maintenance inspection reports, including, but not limited to:
 - (A) Data gathered through integrity assessments required under this part, including, but not limited to, in-line inspections, pressure tests, direct assessments, guided wave ultrasonic testing, or other methods;
 - (B) Close interval survey (CIS) and electrical survey results;
 - (C) CP rectifier readings;
 - (D) CP test point survey readings and locations;
 - (E) Alternating current, direct current, and foreign structure interference surveys;
 - (F) Pipe coating surveys, including surveys to detect coating damage, disbanded coatings, or other conditions that compromise the effectiveness of corrosion protection, including, but not limited to, direct current voltage gradient or alternating current voltage gradient inspections;

- (G) Results of examinations of exposed portions of buried pipelines (e.g., pipe and pipe coating condition, see § 192.459), including the results of any non-destructive examinations of the pipe, seam, or girth weld (i.e. bell hole inspections);
 - (H) Stress corrosion cracking excavations and findings;
 - (I) Selective seam weld corrosion excavations and findings;
 - (J) Any indication of seam cracking; and
 - (K) Gas stream sampling and internal corrosion monitoring results, including cleaning pig sampling results;
- (xxv) External and internal corrosion monitoring;
 - (xxvi) Operating pressure history and pressure fluctuations, including an analysis of effects of pressure cycling and instances of exceeding MAOP by any amount;
 - (xxvii) Performance of regulators, relief valves, pressure control devices, or any other device to control or limit operating pressure to less than MAOP;
 - (xxviii) Encroachments;
 - (xxix) Repairs;
 - (xxx) Vandalism;
 - (xxxi) External forces;
 - (xxxii) Audits and reviews;
 - (xxxiii) Industry experience for incident, leak, and failure history;
 - (xxxiv) Aerial photography; and
 - (xxxv) Exposure to natural forces in the area of the pipeline, including seismicity, geology, and soil stability of the area.
- (2) Use validated information and data as inputs, to the maximum extent practicable. If input is obtained from subject matter experts (SME), an operator must employ adequate control measures to ensure consistency and accuracy of information. Control measures may include training of SMEs or the use of outside technical experts (independent expert reviews) to assess the quality of processes and the judgment of SMEs. An operator must document the names and qualifications of the individuals who approve SME inputs used in the current risk assessment.
 - (3) Identify and analyze spatial relationships among anomalous information (e.g., corrosion coincident with foreign line crossings or evidence of pipeline damage where overhead imaging shows evidence of encroachment).
 - (4) Analyze the data for interrelationships among pipeline integrity threats, including combinations of applicable risk factors that increase the likelihood of incidents or increase the potential consequences of incidents.
- (c) *Risk assessment.* An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and that analyzes considers the identified threats and potential consequences of an incident for each covered segment. ~~An operator must use the risk~~

~~assessment to prioritize the covered segments for the baseline and continual reassessments (§§ 192.919, 192.921, 192.937), and to determine what additional preventive and mitigative measures are needed (§192.935) for the covered segment. An operator must ensure the validity of the methods used to conduct the risk assessment considering the incident, leak, and failure history of the pipeline segments and other historical information. Such a validation must ensure the risk assessment methods produce a risk characterization that is consistent with the operator's and industry experience, including evaluations of the cause of past incidents, as determined by root cause analysis or other equivalent means, and include sensitivity analysis of the factors used to characterize both the likelihood of loss of pipeline integrity and consequences of the postulated loss of pipeline integrity. An operator must use the risk assessment to determine additional preventive and mitigative measures needed for each covered segment in accordance with § 192.935 and periodically evaluate the integrity of each covered pipeline segment in accordance with § 192.937. Beginning February 26, 2024, the risk assessment must:~~

- ~~(1) Analyze how a potential failure could affect high consequence areas;~~
 - ~~(2) Analyze the likelihood of failure due to each individual threat and each unique combination of threats that interact or simultaneously contribute to risk at a common location;~~
 - ~~(3) Account for, and compensate for, uncertainties in the model and the data used in the risk assessment; and~~
 - ~~(4) Evaluate the potential risk reduction associated with candidate risk reduction activities, such as preventive and mitigative measures, and reduced anomaly remediation and assessment intervals.~~
 - ~~(5) In conjunction with § 192.917(b), an operator may request an extension of up to 1 year for the requirements of this paragraph by submitting a notification to PHMSA at least 90 days before February 26, 2024, in accordance with § 192.18. The notification must include a reasonable and technically justified basis, an up-to-date plan for completing all actions required by this paragraph (c)(5), the reason for the requested extension, current safety or mitigation status of the pipeline segment, the proposed completion date, and any needed temporary safety measures to mitigate the impact on safety.~~
- (d) *Plastic Transmission Pipeline.* An operator of a plastic transmission pipeline must assess the threats to each covered segment using the information in sections 4 and 5 of ASME B31.8S, and consider any threats unique to the integrity of plastic pipe, such as poor joint fusion practices, pipe with poor slow crack growth (SCG) resistance, brittle pipe, circumferential cracking, hydrocarbon, softening of the pipe, internal and external loads, longitudinal or lateral loads, proximity to elevated heat sources, and point loading.
- (e) *Actions to address particular threats.* If an operator identifies any of the following threats, the operator must take the following actions to address the threat.
- (1) *Third party damage.* An operator must utilize the data integration required in paragraph (b) of this section and ASME/ANSI B31.8S, Appendix ~~A7 A-8~~ to determine the susceptibility of each covered segment to the threat of third-party damage. If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with § 192.935 and monitor the effectiveness of the preventive measures. If, in conducting a baseline assessment under § 192.921, or a reassessment under §

192.937, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third-party damage may exist in the covered segment. An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration.

- (2) **Cyclic fatigue.** An operator must analyze and account for whether cyclic fatigue or other loading conditions (including ground movement, and suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, crack, or other defect in the covered segment. The analysis must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the analysis together with the criteria used to determine the significance of the threat(s) to the covered segment to prioritize the integrity baseline assessment or reassessment. Failure stress pressure and crack growth analysis of cracks and crack-like defects must be conducted in accordance with § 192.712. An operator must monitor operating pressure cycles and periodically, but at least every 7 calendar years, with intervals not to exceed 90 months, determine if the cyclic fatigue analysis remains valid or if the cyclic fatigue analysis must be revised based on changes to operating pressure cycles or other loading conditions.
- (3) ***Manufacturing and construction defects.*** An operator must analyze the covered segment to determine and account for the risk of failure from manufacturing and construction defects (including seam defects) in the covered segment. The analysis must account for the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects only if the covered segment has been subjected to hydrostatic pressure testing satisfying the criteria of subpart J of at least 1.25 times MAOP, and the covered segment has not experienced a reportable incident attributed to a manufacturing or construction defect since the date of the most recent subpart J pressure test. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high-risk segment for the baseline assessment or a subsequent reassessment.
 - (i) The pipeline segment has experienced a reportable incident, as defined in § 191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, or a construction, installation-, or fabrication-related defect;
 - (ii) MAOP increases; or
 - (iii) The stresses leading to cyclic fatigue increase.
- (4) ***Electric Resistance Welded (ERW) pipe.*** If a covered pipeline segment contains low frequency ERW pipe, lap welded pipe, pipe with longitudinal joint factor less than 1.0 as defined in § 192.113, or other pipe that satisfies the conditions specified in ASME/~~ANSI~~ B31.8S, Appendices ~~A4.3 and A4.4~~ A-5.3 and A-5.4, and any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure (including seam cracking and selective seam weld corrosion), or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding 5 years (including abnormal operation as defined in § 192.605(c)), or MAOP has been

increased, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high-risk segment for the baseline assessment or a subsequent reassessment. Pipe with seam cracks must be evaluated using fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis to estimate the remaining life of the pipe in accordance with § 192.712. Corrosion. If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in § 192.933), the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's established operating and maintenance procedures under Part 192 for testing and repair.

- (5) *Corrosion.* If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in § 192.933), the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's established operating and maintenance procedures under part 192 for testing and repair.
- (6) *Cracks.* If an operator identifies any crack or crack-like defect (e.g., stress corrosion cracking or other environmentally assisted cracking, seam defects, selective seam weld corrosion, girth weld cracks, hook cracks, and fatigue cracks) on a covered pipeline segment that could adversely affect the integrity of the pipeline, the operator must evaluate, and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar characteristics associated with the crack or crack-like defect. Similar characteristics may include operating and maintenance histories, material properties, and environmental characteristics. An operator must establish a schedule for evaluating, and remediating, as necessary, the similar pipeline segments that is consistent with the operator's established operating and maintenance procedures under this part for testing and repair.

§ 192.919 What must be in the baseline assessment plan?

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

- (a) Identification of the potential threats to each covered pipeline segment and the information supporting the threat identification. (See §192.917.);
- (b) The methods selected to assess the integrity of the line pipe, including an explanation of why the assessment method was selected to address the identified threats to each covered segment. The integrity assessment method an operator uses must be based on the threats identified to the covered segment. (See § 192.917.) More than one method may be required to address all the threats to the covered pipeline segment;
- (c) A schedule for completing the integrity assessment of all covered segments, including, risk factors considered in establishing the assessment schedule;
- (d) If applicable, a direct assessment plan that meets the requirements of §§ 192.923, and

depending on the threat to be addressed, of § 192.925, § 192.927, or § 192.929; and

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

§ 192.921 How is the baseline assessment to be conducted?

- (a) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods for each threat to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (See § 192.917).
 - (1) Internal inspection tool or tools capable of detecting those threats to which the pipeline is susceptible. The use of internal inspection tools is appropriate for threats such as corrosion, deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (e.g., stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493. In addition, an operator must analyze and account for uncertainties in reported results (e.g., tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies;
 - (2) Pressure test conducted in accordance with subpart J of this part. The use of subpart J pressure testing is appropriate for threats such as internal corrosion; external corrosion and other environmentally assisted corrosion mechanisms; manufacturing and related defects threats, including defective pipe and pipe seams; stress corrosion cracking; selective seam weld corrosion; dents; and other forms of mechanical damage. An operator must use the test pressures specified in Table ~~3 5.6.1-1~~ of section 5 of ASME/~~ANSI~~ B31.8S (incorporated by reference, see § 192.7) to justify an extended reassessment interval in accordance with § 192.939.
 - (3) Spike hydrostatic pressure test conducted in accordance with § 192.506. The use of spike hydrostatic pressure testing is appropriate for time-dependent threats such as stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects;
 - (4) Excavation and *in situ* direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), inverse wave field extrapolation (IWEX), radiography, and magnetic particle inspection (MPI);
 - (5) Guided wave ultrasonic testing (GWUT) as described in Appendix F. The use of GWUT is appropriate for internal and external pipe wall loss;
 - (6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of direct assessment to address threats of

external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and the pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in §§ 192.925, 192.927 and 192.929; or

- (7) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify PHMSA in advance of using the other technology in accordance with § 192.18.
- (b) *Prioritizing segments.* An operator must prioritize the covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats to each covered segment. The risk analysis must comply with the requirements in § 192.917.
- (c) *Assessment for particular threats.* In choosing an assessment method for the baseline assessment of each covered segment, an operator must take the actions required in § 192.917(e) to address particular threats that it has identified.
- (d) *Time period.* An operator must prioritize all the covered segments for assessment in accordance with § 192.917 (c) and paragraph (b) of this section. An operator must assess at least 50% of the covered segments beginning with the highest risk segments, by December 17, 2007. An operator must complete the baseline assessment of all covered segments by December 17, 2012.
- (e) *Prior assessment.* An operator may use a prior integrity assessment conducted before December 17, 2002 as a baseline assessment for the covered segment, if the integrity assessment meets the baseline requirements in this subpart and subsequent remedial actions to address the conditions listed in § 192.933 have been carried out. In addition, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe in the covered segment according to the requirements of § 192.937 and § 192.939.
- (f) *Newly identified areas.* When an operator identifies a new high consequence area (see § 192.905), an operator must complete the baseline assessment of the line pipe in the newly identified high consequence area within ten (10) years from the date the area is identified.
- (g) *Newly installed pipe.* An operator must complete the baseline assessment of a newly installed segment of pipe covered by this subpart within ten (10) years from the date the pipe is installed. An operator may conduct a pressure test in accordance with paragraph (a)(2) of this section, to satisfy the requirement for a baseline assessment.
- (h) *Plastic transmission pipeline.* If the threat analysis required in § 192.917(d) on a plastic transmission pipeline indicates that a covered segment is susceptible to failure from causes other than third-party damage, an operator must conduct a baseline assessment of the segment in accordance with the requirements of this section and of § 192.917. The operator must justify the use of an alternative assessment method that will address the identified threats to the covered segment.
- (i) Baseline assessments for pipeline segments with a reconfirmed MAOP. An integrity assessment conducted in accordance with the requirements of § 192.624(c) may be used as a baseline assessment under this section.

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

- (a) *General.* An operator may use direct assessment either as a primary assessment method or as a supplement to the other assessment methods allowed under this subpart. An operator may only use direct assessment as the primary assessment method to address the identified threats of external corrosion (EC), internal corrosion (IC), and stress corrosion cracking (SCC).
- (b) *Primary method.* An operator using direct assessment as a primary assessment method must have a plan that complies with the requirements in –
 - (1) Section 192.925 and ASME/~~ANSI~~ B31.8S (incorporated by reference, see § 192.7), ~~sSection~~ 6.4, and NACE SP0502 (incorporated by reference, see § 192.7), if addressing external corrosion (EC).
 - (2) Section 192.927 and ~~ASME/ANSI B31.8S~~ NACE SP0206 (incorporated by reference, see § 192.7), ~~section 6.4, Appendix B2~~, if addressing internal corrosion (IC).
 - (3) Section 192.929 and ~~ASME/ANSI B31.8S~~NACE SP0204 (incorporated by reference, see § 192.7), ~~Appendix A3~~, if addressing stress corrosion cracking (SCC).
- (c) *Supplemental method.* An operator using direct assessment as a supplemental assessment method for any applicable threat must have a plan that follows the requirements for confirmatory direct assessment in § 192.931.

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

- (a) *Definition.* ECDA is a four-step process that combines preassessment, indirect inspection, direct examination, and post assessment to evaluate the threat of external corrosion to the integrity of a pipeline.
- (b) *General requirements.* An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/~~ANSI~~ B31.8S (incorporated by reference, see § 192.7), section 6.4, and in NACE SP0502 (incorporated by reference, see § 192.7). An operator must develop and implement a direct assessment plan that has procedures addressing pre-assessment, indirect inspection, direct examination, and post- assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (§ 192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by § 192.917 (e)(1).
 - (1) *Preassessment.* In addition to the requirements in ASME/~~ANSI~~ B31.8S section 6.4 and NACE SP0502, section 3, the plan’s procedures for preassessment must include -
 - (i) Provisions applying more restrictive criteria when conducting ECDA for the first time on a covered segment; and
 - (ii) The basis on which an operator selects at least two different, but complementary indirect assessment tools to assess each ECDA Region. If an operator utilizes an indirect inspection method that is not discussed in Appendix A of NACE SP0502, the operator must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.
 - (2) *Indirect inspection.* In addition to the requirements in ASME/~~ANSI~~ B31.8S, section 6.4 and NACE SP0502, section 4, the plan’s procedures for indirect inspection of

the ECDA regions must include -

- (i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;
 - (ii) Criteria for identifying and documenting those indications that must be considered for excavation and direct examination. Minimum identification criteria include the known sensitivities of assessment tools, the procedures for using each tool, and the approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected;
 - (iii) Criteria for defining the urgency of excavation and direct examination of each indication identified during the indirect examination. These criteria must specify how an operator will define the urgency of excavating the indication as immediate, scheduled or monitored; and
 - (iv) Criteria for scheduling excavation of indications for each urgency level.
- (3) *Direct examination.* In addition to the requirements in ASME/~~ANSI~~ B31.8S section 6.4 and NACE SP0502, section 5, the plan's procedures for direct examination of indications from the indirect examination must include -
- (i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;
 - (ii) Criteria for deciding what action should be taken if either:
 - (A) Corrosion defects are discovered that exceed allowable limits (Section 5.5.2.2 of NACE SP0502), or
 - (B) Root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE SP0502);
 - (iii) Criteria and notification procedures for any changes in the ECDA Plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications; and
 - (iv) Criteria that describe how and on what basis an operator will reclassify and reprioritize any of the provisions that are specified in section 5.9 of NACE SP0502
- (4) *Post assessment and continuing evaluation.* In addition to the requirements in ASME/~~ANSI~~ B31.8S section 6.4 and NACE SP0502, section 6, the plan's procedures for post assessment of the effectiveness of the ECDA process must include -
- (i) Measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion in covered segments; and
 - (ii) Criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the covered segment at an interval less than that specified in § 192.939. (See Appendix D of NACE SP0502.)

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

- (a) *Definition.* Internal Corrosion Direct Assessment (ICDA) is a process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal

operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO₂, O₂, hydrogen sulfide or other contaminants present in the gas.

- (b) ~~*General requirements.* An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in ASME/ANSI B31.8S (incorporated by reference, see § 192.7), section 6.4 and Appendix B2. The ICDA process described in this section applies only for a segment of pipe transporting nominally dry natural gas, and not for a segment with electrolyte nominally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolyte present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to effectively address internal corrosion, and must provide notification in accordance with § 192.921(a)(4) or § 192.937(c)(4).~~ *General requirements.* An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in NACE SP0206 (incorporated by reference, see § 192.7). The Dry Gas Internal Corrosion Direct Assessment (DG-ICDA) process described in this section applies only for a segment of pipe transporting normally dry natural gas (see § 192.3) and not for a segment with electrolytes normally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolytes present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to address internal corrosion effectively and must notify PHMSA in accordance with § 192.18. In the event of a conflict between this section and NACE SP0206, the requirements in this section control.
- (c) ~~*The ICDA plan.* An operator must develop and follow an ICDA plan that provides for preassessment, identification of ICDA regions and excavation locations, detailed examination of pipe at excavation locations, and post-assessment evaluation and monitoring.~~
- (7) ~~*Preassessment.* In the preassessment stage, an operator must gather and integrate data and information needed to evaluate the feasibility of ICDA for the covered segment, and to support use of a model to identify the locations along the pipe segment where electrolyte may accumulate, to identify ICDA regions, and to identify areas within the covered segment where liquids may potentially be entrained. This data and information includes, but is not limited to~~
- (i) ~~All data elements listed in Appendix A2 of ASME/ANSI B31.8S;~~
 - (ii) ~~Information needed to support use of a model that an operator must use to identify areas along the pipeline where internal corrosion is most likely to occur. (See paragraph (a) of this section.) This information, includes, but is not limited to, location of all gas input and withdrawal points on the line; location of all low points on covered segments such as sags, drips, inclines, valves, manifolds, dead legs, and traps; the elevation profile of the pipeline in sufficient detail that angles of inclination can be calculated for all pipe segments; and the diameter of the pipeline, and the range of expected gas velocities in the pipeline;~~
 - (iii) ~~Operating experience data that would indicate historic upsets in gas conditions, locations where these upsets have occurred, and potential damage resulting from these upset conditions; and~~

- ~~(iv) Information on covered segments where cleaning pigs may not have been used or where cleaning pigs may deposit electrolytes.~~
- ~~(2) ICDA region identification. An plan must identify where all ICDA Regions are located in the transmission system, in which covered segments are located. An ICDA Region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur and where further evaluation is needed. An ICDA Region may encompass one or more covered segments. In the identification process, an operator must use the model in GRI 02-0057, Corrosion Direct Assessment of Gas Transmission Pipelines (incorporated by reference, see § 192.7). An operator may use another model if the operator demonstrates it is equivalent to the one shown in GRI 02-0057. A model must consider changes in pipe diameter, locations where gas enters a line (potential to introduce liquid) and locations downstream of gas draw offs (where gas velocity is reduced) to define the critical pipe angle of inclination above which water film cannot be transported by the gas.~~
- ~~(3) Identification of locations for excavation and direct examination. An plan must identify the locations where internal corrosion is most likely in each ICDA region. In the location identification process, an operator must identify a minimum of two locations for excavation within each ICDA Region within a covered segment and must perform a direct examination for internal corrosion at each location, using ultrasonic thickness measurements, radiography, or other generally accepted measurement technique. One location must be the low point (e.g., sags, drips, valves, manifolds, dead legs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further downstream, within a covered segment, near the end of the ICDA Region. If corrosion exists at either location, the operator must
 - ~~(i) Evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with § 192.933;~~
 - ~~(ii) As part of the operator's current integrity assessment either perform additional excavations in each covered segment within the ICDA region, or use an alternative assessment method allowed by this subpart to assess the line pipe in each covered segment within the ICDA region for internal corrosion; and~~
 - ~~(iii) Evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the pipeline system with similar characteristics to the ICDA region containing the covered segment in which the corrosion was found, and as appropriate, remediate the conditions the operator finds in accordance with § 192.933.~~~~
- ~~(4) Post-assessment evaluation and monitoring. An plan must provide for evaluating the effectiveness of the ICDA process and continued monitoring of covered segments where internal corrosion has been identified. The evaluation and monitoring process includes
 - ~~(i) Evaluating the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in § 192.939. An operator must carry out this evaluation within a year of conducting an ICDA; and~~~~

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

 - ~~(A) Conduct excavations of covered segments at locations downstream from where the electrolyte might have entered the pipe; or~~
 - ~~(B) Assess the covered segment using another integrity assessment method allowed by this subpart.~~~~
- ~~(5) Other requirements. The ICDA plan must also include—

 - ~~(i) Criteria an operator will apply in making key decisions (e.g., ICDA feasibility, definition of ICDA Regions, conditions requiring excavation) in implementing each stage of the ICDA process;~~
 - ~~(ii) Provisions for applying more restrictive criteria when conducting ICDA for the first time on a covered segment and that become less stringent as the operator gains experience; and~~
 - ~~(iii) Provisions that analysis be carried out on the entire pipeline in which covered segments are present, except that application of the remediation criteria of § 192.933 may be limited to covered segments.~~~~
- (c) The ICDA plan. An operator must develop and follow an ICDA plan that meets NACE SP0206 (incorporated by reference, see § 192.7) and that implements all four steps of the DG-ICDA process, including pre-assessment, indirect inspection, detailed examination at excavation locations, and post-assessment evaluation and monitoring. The plan must identify the locations of all ICDA regions within covered segments in the transmission system. An ICDA region is a continuous length of pipe (including weld joints), uninterrupted by any significant change in water or flow characteristics, that includes similar physical characteristics or operating history. An ICDA region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur until a new input introduces the possibility of water entering the pipeline. In cases where a single covered segment is partially located in two or more ICDA regions, the four-step ICDA process must be completed for each ICDA region in which the covered segment is partially located to complete the assessment of the covered segment.
 - (1) Preassessment. An operator must comply with NACE SP0206 (incorporated by reference, see § 192.7) in conducting the preassessment step of the ICDA process.
 - (2) Indirect inspection. An operator must comply with NACE SP0206 (incorporated by reference, see § 192.7), and the following additional requirements, in conducting the Indirect Inspection step of the ICDA process. An operator must explicitly

document the results of its feasibility assessment as required by NACE SP0206, section 3.3 (incorporated by reference, see § 192.7); if any condition that precludes the successful application of ICDA applies, then ICDA may not be used, and another assessment method must be selected. When performing the indirect inspection, the operator must use actual pipeline-specific data, exclusively. The use of assumed pipeline or operational data is prohibited. When calculating the critical inclination angle of liquid holdup and the inclination profile of the pipeline, the operator must consider the accuracy, reliability, and uncertainty of the data used to make those calculations, including, but not limited to, gas flow velocity (including during upset conditions), pipeline elevation profile survey data (including specific profile at features with inclinations such as road crossings, river crossings, drains, valves, drips, etc.), topographical data, and depth of cover. An operator must select locations for direct examination and establish the extent of pipe exposure needed (i.e., the size of the bell hole), to account for these uncertainties and their cumulative effect on the precise location of predicted liquid dropout.

- (3) *Detailed examination.* An operator must comply with NACE SP0206 (incorporated by reference, see § 192.7) in conducting the detailed examination step of the ICDA process. When an operator first uses ICDA for a covered segment, an operator must identify a minimum of two locations for excavation within each covered segment associated with the ICDA region and must perform a detailed examination for internal corrosion at each location using ultrasonic thickness measurements, radiography, or other generally accepted measurement techniques that can examine for internal corrosion or other threats that are being assessed. One location must be the low point (e.g., sag, drip, valve, manifold, dead-leg) within the covered segment nearest to the beginning of the ICDA region. The second location must be further downstream, within the covered segment, near the end of the ICDA region. Whenever corrosion is found during ICDA at any location, the operator must:
- (i) Evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with § 192.933 if the condition is in a covered segment, or in accordance with §§ 192.485 and 192.714 if the condition is not in a covered segment;
 - (ii) Expand the detailed examination program to determine all locations that have internal corrosion within the ICDA region, and accurately characterize the nature, extent, and root cause of the internal corrosion. In cases where the internal corrosion was identified within the ICDA region but outside the covered segment, the expanded detailed examination program must also include at least two detailed examinations within each covered segment associated with the ICDA region, at the location within the covered segment(s) most likely to have internal corrosion. One location must be the low point (e.g., sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA region. The second location must be further downstream, within the covered segment. In instances of first use of ICDA for a covered segment, where these locations have already been examined in accordance with paragraph (c)(3) of this section, two additional detailed examinations must be conducted within the covered segment; and

- (iii) Expand the detailed examination program to evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA region in which the corrosion was found and remediate identified instances of internal corrosion in accordance with either § 192.933 or §§ 192.485 and 192.714, as appropriate.
- (4) Post-assessment evaluation and monitoring. An operator must comply with NACE SP0206 (incorporated by reference, see § 192.7) in performing the post assessment step of the ICDA process. In addition to NACE SP0206, the evaluation and monitoring process must also include—
 - (i) An evaluation of the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in § 192.939. An operator must carry out this evaluation within 1 year of conducting an ICDA;
 - (ii) Validation of the flow modeling calculations by comparison of actual locations of discovered internal corrosion with locations predicted by the model (if the flow model cannot be validated, then ICDA is not feasible for the segment); and
 - (iii) Continuous monitoring of each ICDA region that contains a covered segment where internal corrosion has been identified by using techniques such as coupons or ultrasonic (UT) sensors or electronic probes, and by periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this subpart and risk factors specific to the ICDA region. At a minimum, the monitoring frequency must be two times each calendar year, but at intervals not exceeding 7 1/2 months. If an operator finds any evidence of corrosion products in the ICDA region, the operator must take prompt action in accordance with one of the two following required actions, and remediate the conditions the operator finds in accordance with § 192.933 or §§ 192.485 and 192.714, as applicable.
 - (A) Conduct excavations of, and detailed examinations at, locations downstream from where the electrolytes might have entered the pipe to investigate and accurately characterize the nature, extent, and root cause of the corrosion, including the monitoring and mitigation requirements of § 192.478; or
 - (B) Assess the covered segment using another integrity assessment method allowed by this subpart.
- (5) Other requirements. The ICDA plan must also include the following:
 - (i) Criteria an operator will apply in making key decisions (including, but not limited to, ICDA feasibility, definition of ICDA regions and sub-regions, and

conditions requiring excavation) in implementing each stage of the ICDA process; and

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

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

- (a) *Definition.* Stress Corrosion Cracking Direct Assessment (SCCDA) is a process to assess a covered pipe segment for the presence of SCC primarily by systematically gathering and analyzing excavation data for pipe having similar operational characteristics and residing in a similar physical environment.
- (b) *General Requirements.* ~~An operator using direct assessment as an integrity assessment method to address stress corrosion cracking in a covered pipeline segment must have a plan that provides, at minimum, for~~ An operator using direct assessment as an integrity assessment method for addressing SCC in a covered pipeline segment must develop and follow an SCCDA plan that meets NACE SP0204 (incorporated by reference, see § 192.7) and that implements all four steps of the SCCDA process, including pre-assessment, indirect inspection, detailed examination at excavation locations, and post-assessment evaluation and monitoring. As specified in NACE SP0204, SCCDA is complementary with other inspection methods for SCC, such as in-line inspection or hydrostatic testing with a spike test, and it is not necessarily an alternative or replacement for these methods in all instances. Additionally, the plan must provide for—
 - (1) *Data gathering and integration.* ~~An operator's plan must provide for a systematic process to collect and evaluate data for all covered pipeline segments to identify whether the conditions for SCC are present and to prioritize the covered pipeline segments for assessment. This process must include gathering and evaluating data related to SCC at all sites an operator excavates during the conduct of its pipeline operations where the criteria in ASME/ANSI B31.8S (incorporated by reference, see § 192.7), Appendix A3.3 indicate the potential for SCC. This data includes at minimum, the data specified in ASME/ANSI B31.8S, Appendix A3, in accordance with NACE SP0204, sections 3 and 4, and Table 1 (incorporated by reference, see § 192.7). This process must also include gathering and evaluating data related to SCC at all sites an operator excavates while conducting its pipeline operations (both within and outside covered segments) where the criteria in NACE SP0204 (incorporated by reference, see § 192.7) indicate the potential for SCC. This data gathering process must be conducted in accordance with NACE SP0204, section 5.3 (incorporated by reference, see § 192.7), and must include, at a minimum, all data listed in NACE SP0204, Table 2 (incorporated by reference, see § 192.7). Further, the following factors must be analyzed as part of this evaluation:~~
 - (i) The effects of a carbonate-bicarbonate environment, including the implications of any factors that promote the production of a carbonate-bicarbonate environment, such as soil temperature, moisture, the presence or generation of carbon dioxide, or cathodic protection (CP);
 - (ii) The effects of cyclic loading conditions on the susceptibility and propagation of SCC in both high-pH and near-neutral-pH environments;

- (iii) The effects of variations in applied CP, such as overprotection, CP loss for extended periods, and high negative potentials;
 - (iv) The effects of coatings that shield CP when disbanded from the pipe; and
 - (v) Other factors that affect the mechanistic properties associated with SCC, including, but not limited to, historical and present-day operating pressures, high tensile residual stresses, flowing product temperatures, and the presence of sulfides.
- (2) Indirect inspection. In addition to NACE SP0204, the plan's procedures for indirect inspection must include provisions for conducting at least two above ground surveys using the complementary measurement tools most appropriate for the pipeline segment based on an evaluation of integrated data.
 - (3) Direct examination. In addition to NACE SP0204, the plan's procedures for direct examination must provide for an operator conducting a minimum of three direct examinations for SCC within the covered pipeline segment spaced at the locations determined to be the most likely for SCC to occur.
 - (4) Remediation and mitigation. If SCC is discovered in a covered pipeline segment, an operator must mitigate the threat in accordance with one of the following applicable methods:
 - (i) Removing the pipe with SCC; remediating the pipe with a Type B sleeve; performing hydrostatic testing in accordance with paragraph (b)(4)(ii) of this section; or by grinding out the SCC defect and repairing the pipe. If an operator uses grinding for repair, the operator must also perform the following as a part of the repair procedure: nondestructive testing for any remaining cracks or other defects; a measurement of the remaining wall thickness; and a determination of the remaining strength of the pipe at the repair location that is performed in accordance with § 192.712 and that meets the design requirements of §§ 192.111 and 192.112, as applicable. The pipe and material properties an operator uses in remaining strength calculations must be documented in traceable, verifiable, and complete records. If such records are not available, an operator must base the pipe and material properties used in the remaining strength calculations on properties determined and documented in accordance with § 192.607, if applicable.
 - (ii) Performing a spike pressure test in accordance with § 192.506 based upon the class location of the pipeline segment. The MAOP must be no greater than the test pressure specified in § 192.506(a) divided by: 1.39 for Class 1 locations and Class 2 locations that contain Class 1 pipe that has been uprated in accordance with § 192.611; and 1.50 for all other Class 2 locations and all Class 3 and Class 4 locations. An operator must repair any test failures due to SCC by replacing the pipe segment and re-testing the segment until the pipe passes the test without failures (such as pipe seam or gasket leaks, or a pipe rupture). At a minimum, an operator must repair pipe segments that pass the pressure test but have SCC present by grinding the segment in accordance with paragraph (b)(4)(i) of this section.
 - (5) ~~Assessment method. The plan must provide that if conditions for SCC are~~

~~identified in a covered segment, an operator must assess the covered segment using an integrity assessment method specified in ASME/ANSI B31.8S, Appendix A3, and remediate the threat in accordance with ASME/ANSI B31.8S, Appendix A3, section A3.4. Post assessment. An operator's procedures for post-assessment, in addition to the procedures listed in NACE SP0204, sections 6.3, "periodic reassessment," and 6.4, "effectiveness of SCCDA," must include the development of a reassessment plan based on the susceptibility of the operator's pipe to SCC as well as the mechanistic behavior of identified cracking. An operator's reassessment intervals must comply with § 192.939. The plan must include the following factors, in addition to any factors the operator determines appropriate:~~

- ~~(i) The evaluation of discovered crack clusters during the direct examination step in accordance with NACE SP0204, sections 5.3.5.7, 5.4, and 5.5 (incorporated by reference, see § 192.7);~~
- ~~(ii) Conditions conducive to the creation of a carbonate-bicarbonate environment;~~
- ~~(iii) Conditions in the application (or loss) of CP that can create or exacerbate SCC;~~
- ~~(iv) Operating temperature and pressure conditions, including operating stress levels on the pipe;~~
- ~~(v) Cyclic loading conditions;~~
- ~~(vi) Mechanistic conditions that influence crack initiation and growth rates;~~
- ~~(vii) The effects of interacting crack clusters;~~
- ~~(viii) The presence of sulfides; and~~
- ~~(ix) Disbonded coatings that shield CP from the pipe.~~

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

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

- (a) *Threats.* An operator may only use CDA on a covered segment to identify damage resulting from external corrosion or internal corrosion.
- (b) *External corrosion plan.* An operator's CDA plan for identifying external corrosion must comply with § 192.925 with the following exceptions.
 - (1) The procedures for indirect examination may allow use of only one indirect examination tool suitable for the application.
 - (2) The procedures for direct examination and remediation must provide that
 - (i) All immediate action indications must be excavated for each ECDA region; and
 - (ii) At least one high risk indication that meets the criteria of scheduled action must be excavated in each ECDA region.
- (c) *Internal corrosion plan.* An operator's CDA plan for identifying internal corrosion must comply with § 192.927 except that the plan's procedures for identifying locations for excavation may require excavation of only one high risk location in each ICDA region.

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

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

- (a) *General requirements.* An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. ~~In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis is not available, an operator must obtain the undocumented data through § 192.607. Until documented material properties are available, the operator must use the conservative assumptions in either § 192.712(e)(2) or, if appropriate following a pressure test, in § 192.712(d)(3).~~ Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis is not available, an operator must obtain the undocumented data through § 192.607. Until documented material properties are available, the operator must use the conservative assumptions in either § 192.712(e)(2) or, if appropriate following a pressure test, in § 192.712(d)(3).

(1) *Temporary pressure reduction.*

- (i) If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must ~~determine any temporary reduction in operating pressure required by this section using ASME/ANSI B31G (incorporated by reference, see § 192.7); R-STRENG (incorporated by reference, see § 192.7); or by reducing the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. An operator must notify PHMSA in accordance with § 192.18 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through a temporary reduction in operating pressure or through another action.~~ Reduce the operating pressure to one of the following:

- (A) A level not exceeding 80 percent of the operating pressure at the time the condition was discovered;
- (B) A level not exceeding the predicted failure pressure times the design factor for the class location in which the affected pipeline is located; or

- (C) A level not exceeding the predicted failure pressure divided by 1.1.
- (ii) An operator must determine the predicted failure pressure in accordance with § 192.712. An operator must notify PHMSA in accordance with § 192.18 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) or (d) of this section and cannot provide safety through a temporary reduction in operating pressure or other action. The operator must document and keep records of the calculations and decisions used to determine the reduced operating pressure, and the implementation of the actual reduced operating pressure, for a period of 5 years after the pipeline has been remediated.
- (2) *Long-term pressure reduction.* When a pressure reduction exceeds 365 days, an operator must notify PHMSA under § 192.18 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline.
- (b) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. For the purposes of this section, a A-condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable. In cases where a determination is not made within the 180-day period, the operator must notify PHMSA, in accordance with § 192.18, and provide an expected date when adequate information will become available. Notification to PHMSA does not alleviate an operator from the discovery requirements of this paragraph (b).
- (c) *Schedule for evaluation and remediation.* An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/~~ANSI~~ B31.8S (incorporated by reference, see § 192.7), section 7, Figure ~~4.7.2.1-1~~. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.
- (d) *Special requirements for scheduling remediation.*
- (1) *Immediate repair conditions.* An operator's evaluation and remediation schedule must follow ASME/~~ANSI~~ B31.8S, section 7 (incorporated by reference, see § 192.7) in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:
- (i) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include ASME/ANSI B31G (incorporated by reference, see § 192.7), PRCI PR-3-805 (RSTRENG) (incorporated by reference, see

~~§ 192.7), or an alternative equivalent method of remaining strength calculation. A metal loss anomaly where a calculation of the remaining strength of the pipe shows a predicted failure pressure determined in accordance with § 192.712(b) less than or equal to 1.1 times the MAOP at the location of the anomaly.~~

- ~~(ii) A dent that has any indication of metal loss, cracking or a stress riser. A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) that has metal loss, cracking, or a stress riser, unless engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.~~
- ~~(iii) An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action. Metal loss greater than 80 percent of nominal wall regardless of dimensions.~~
- ~~(iv) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.25 times the MAOP.~~
- ~~(v) A crack or crack-like anomaly meeting any of the following criteria:
 - ~~(A) Crack depth plus any metal loss is greater than 50 percent of pipe wall thickness;~~
 - ~~(B) Crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth; or~~
 - ~~(C) The crack or crack-like anomaly has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.25 times the MAOP.~~~~
- ~~(vi) An indication or anomaly that, in the judgment of the person designated by the operator to evaluate the assessment results, requires immediate action.~~

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

- ~~(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless engineering analyses performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.~~
- ~~(ii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld, unless engineering analyses performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.~~
- ~~(iii) A dent located between the 4 o'clock and 8 o'clock positions (lower 1/3 of~~

the pipe) that has metal loss, cracking, or a stress riser, unless engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

- (iv) Metal loss anomalies where a calculation of the remaining strength of the pipe at the location of the anomaly shows a predicted failure pressure, determined in accordance with § 192.712(b), less than 1.39 times the MAOP for Class 2 locations, and less than 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME B31.8S (incorporated by reference, see § 192.7), section 7, Figure 4, in accordance with paragraph (c) of this section.
- (v) Metal loss that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or could affect a girth weld, that has a predicted failure pressure, determined in accordance with § 192.712(b), of less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.
- (vi) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d), is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.
- (vii) A crack or crack-like anomaly that has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

- (3) ~~Monitored conditions. An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:~~ An operator is not required by this section to schedule remediation of the following less severe conditions but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation. Monitored indications are the least severe and do not require an operator to examine and evaluate them until the next scheduled integrity assessment interval, but if an anomaly is expected to grow to dimensions or have a predicted failure pressure (with a safety factor) meeting a 1-year condition prior to the next scheduled assessment, then the operator must repair the condition:

- (i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the

- pipe) and for which engineering analyses of the dent, performed in accordance with § 192.712(c), demonstrate critical strain levels are not exceeded.
- (ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and for which engineering analyses of the dent, performed in accordance with § 192.712(c), demonstrate critical strain levels are not exceeded.
 - (iii) A dent with a depth greater than 2% of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal or helical (spiral) seam weld, and for which engineering analyses, performed in accordance with § 192.712(c), of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.
 - (iv) A dent that has metal loss, cracking, or a stress riser, and where engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.
 - (v) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.
 - (vi) A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.
- (e) In situ direct examination of crack defects. Whenever an operator finds conditions that require the pipeline to be repaired, in accordance with this section, an operator must perform a direct examination of known locations of cracks or crack-like defects using technology that has been validated to detect tight cracks (equal to or less than 0.008 inches crack opening), such as inverse wave field extrapolation (IWEX), phased array ultrasonic testing (PAUT), ultrasonic testing (UT), or equivalent technology. "In situ" examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection for accuracy of the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations.

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

(a) *General Requirements.*

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

- (i) Correcting the root causes of past incidents to prevent recurrence;
- (ii) Establishing and implementing adequate operations and maintenance processes that could increase safety;
- (iii) Establishing and deploying adequate resources for the successful execution of preventive and mitigative measures;
- (iv) Installing automatic shut-off valves or remote-control valves;
- (v) Installing pressure transmitters on both sides of automatic shut-off valves and remote-control valves that communicate with the pipeline control center;
- (vi) Installing computerized monitoring and leak detection systems;
- (vii) Replacing pipe segments with pipe of heavier wall thickness or higher strength;
- (viii) Conducting additional right-of-way patrols;
- (ix) Conducting hydrostatic tests in areas where pipe material has quality issues or lost records;
- (x) Testing to determine material mechanical and chemical properties for unknown properties that are needed to assure integrity or substantiate MAOP evaluations, including material property tests from removed pipe that is representative of the in-service pipeline;
- (xi) Re-coating damaged, poorly performing, or disbonded coatings;
- (xii) Performing additional depth-of-cover surveys at roads, streams, and rivers;
- (xiii) Remediating inadequate depth-of-cover;
- (xiv) Providing additional training to personnel on response procedures and conducting drills with local emergency responders; and
- (xv) Implementing additional inspection and maintenance programs.

- (2) Operators must document the risk analysis, the preventive and mitigative measures considered, and the basis for implementing or not implementing any preventive and mitigative measures considered, in accordance with § 192.947(d).
- (b) *Third Party Damage and Outside Force Damage.*
- (1) *Third party damage.* An operator must enhance its damage prevention program, as required under § 192.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures to an existing damage prevention program include, at a minimum -
- (i) Using qualified personnel (see § 192.915) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.
 - (ii) Collecting in a central database information that is location specific on excavation damage that occurs in covered and non-covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under Part 191.
 - (iii) Participating in one-call systems in locations where covered segments are present.
 - (iv) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE SP0502 (incorporated by reference, see § 192.7). An operator must excavate, and remediate, in accordance with ANSI/ASME ASME B31.8S and §192.933 any indication of coating holidays or discontinuity warranting direct examination.
- (2) *Outside force damage.* If an operator determines that outside force (e.g., earth movement, loading, longitudinal, or lateral forces, seismicity of the area, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include increasing the frequency of aerial, foot or other methods of patrols; adding external protection; reducing external stress; relocating the line; or inline inspections with geospatial and deformation tools. *Automatic shut-off valves (ASV) or Remote-control valves (RCV).* If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors - swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.
- (c) Risk analysis for gas releases and protection against ruptures. If an operator determines, based on a risk analysis, that a rupture-mitigation valve (RMV) or alternative equivalent technology would be an efficient means of adding protection to a high-consequence area

(HCA) in the event of a gas release, an operator must install the RMV or alternative equivalent technology. In making that determination, an operator must, at least, evaluate the following factors—timing of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel. An RMV or alternative equivalent technology installed under this paragraph must meet all of the other applicable requirements in this part.

- (d) *Pipelines operating below 30% SMYS.* An operator of a transmission pipeline operating below 30% SMYS located in a high consequence area must follow the requirements in paragraphs (d)(1) and (d)(2) of this section. An operator of a transmission pipeline operating below 30% SMYS located in a Class 3 or Class 4 area but not in a high consequence area must follow the requirements in paragraphs (d)(1), (d)(2) and (d)(3) of this section.
- (1) Apply the requirements in paragraphs (b)(1)(i) and (b)(1)(iii) of this section to the pipeline; and
 - (2) Either monitor excavations near the pipeline, or conduct patrols as required by § 192.705 of the pipeline at bi-monthly intervals. If an operator finds any indication of unreported construction activity, the operator must conduct a follow up investigation to determine if mechanical damage has occurred.
 - (3) Perform semi-annual leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where electrical surveys are impractical). Perform instrumented leak surveys using leak detector equipment at least twice each calendar year, at intervals not exceeding 7 1/2 months. For unprotected pipelines or cathodically protected pipe where electrical surveys are impractical, instrumented leak surveys must be performed at least four times each calendar year, at intervals not exceeding 4 1/2 months. Electrical surveys are indirect assessments that include close interval surveys, alternating current voltage gradient surveys, direct current voltage gradient surveys, or their equivalent.
- (e) *Plastic transmission pipeline.* An operator of a plastic transmission pipeline must apply the requirements in paragraphs (b)(1)(i), (b)(1)(iii) and b(1)(iv) of this section to the covered segments of the pipeline.
- (f) *Periodic evaluations. Risk analyses and assessments conducted under paragraph (c) of this section must be reviewed by the operator and certified by a senior executive of the company, for operational matters that could affect rupture-mitigation processes and procedures. Review and certification must occur once per calendar year, with the period between reviews not to exceed 15 months, and must also occur within 3 months of an incident or safety-related condition, as those terms are defined at §§ 191.3 and 191.23, respectively.*

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

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

later than seven years after the baseline assessment of that covered segment unless the evaluation under paragraph (b) of this section indicates earlier reassessment.

- (b) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in § 192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in §192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§ 192.917), and decisions about remediation (§ 192.933) and additional preventive and mitigative actions (§ 192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.
- (c) *Assessment methods.* In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in the covered segment by applying one or more of the following methods for each threat to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified on the covered segment (see § 192.917).
- (1) *Internal inspection tools.* When performing an assessment using an in-line inspection tool, an operator must comply with the following requirements:
- (i) Perform the in-line inspection in accordance with § 192.493;
 - (ii) Select a tool or combination of tools capable of detecting the threats to which the pipeline segment is susceptible such as corrosion, deformation and mechanical damage (e.g. dents, gouges and grooves), material cracking and crack-like defects (e.g. stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible; and
 - (iii) Analyze and account for uncertainties in reported results (e.g., tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies.
- (2) *Pressure test conducted in accordance with subpart J of this part.* The use of pressure testing is appropriate for threats such as: Internal corrosion; external corrosion and other environmentally assisted corrosion mechanisms; manufacturing and related defects threats, including defective pipe and pipe seams; stress corrosion cracking; selective seam weld corrosion; dents; and other forms of mechanical damage. An operator must use the test pressures specified in table 3 of section 5 of ASME/~~ANSI~~ B31.8S (incorporated by reference, see § 192.7) to justify an extended reassessment interval in accordance with § 192.939.
- (3) *Spike hydrostatic pressure test in accordance with § 192.506.* The use of spike hydrostatic pressure testing is appropriate for time-dependent threats such as: Stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects;

- (4) Excavation and *in situ* direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), inverse wave field extrapolation (IWEX), radiography, or magnetic particle inspection (MPI);
 - (5) Guided wave ultrasonic testing (GWUT) as described in Appendix F. The use of GWUT is appropriate for internal and external pipe wall loss;
 - (6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in §§ 192.925, 192.927, and 192.929;
 - (7) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify PHMSA in advance of using the other technology in accordance with § 192.18; or
 - (8) Confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than 7 calendar years. An operator using this reassessment method must comply with § 192.931.
- (d) *MAOP reconfirmation assessments.* An integrity assessment conducted in accordance with the requirements of § 192.624(c) may be used as a reassessment under this section.

§ 192.939 What are the required reassessment intervals?

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

- (a) *Pipelines operating at or above 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is 7 calendar years. Operators may request a 6-month extension of the 7-calendar-year reassessment interval if the operator submits written notice to OPS, in accordance with § 192.18, with sufficient justification of the need for the extension. If an operator establishes a reassessment interval that is greater than 7 calendar years, the operator must, within the 7-calendar-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with § 192.931. The table that follows this section sets forth the maximum allowed reassessment intervals.
 - (1) *Pressure test or internal inspection or other equivalent technology.* An operator that uses pressure testing or internal inspection as an assessment method must establish the reassessment interval for a covered pipeline segment by -
 - (i) Basing the interval on the identified threats for the covered segment (see § 192.917) and on the analysis of the results from the last integrity assessment and from the data integration and risk assessment required

by § 192.917; or

- (ii) Using the intervals specified for different stress levels of pipeline (operating at or above 30% SMYS) listed in ASME B31.8S (incorporated by reference, see § 192.7), ~~section 5~~, Table ~~3~~ 5.6.1-1 of Section 5.
- (2) *External Corrosion Direct Assessment.* An operator that uses ECDA that meets the requirements of this subpart must determine the reassessment interval according to the requirements in paragraphs 6.2 and 6.3 of NACE SP0502 (incorporated by reference, see § 192.7).
 - (3) *Internal Corrosion or SCC Direct Assessment.* An operator that uses ICDA or SCCDA in accordance with the requirements of this subpart must determine the reassessment interval according to the following method. However, the reassessment interval cannot exceed those specified for direct assessment in ~~ASME/ANSI B31.8S, section 5, Table 3~~ ASME B31.8S, Table 5.6.1-1 of Section 5.
 - (i) Determine the largest defect most likely to remain in the covered segment and the corrosion rate appropriate for the pipe, soil and protection conditions;
 - (ii) Use the largest remaining defect as the size of the largest defect discovered in the SCC or ICDA segment; and
 - (iii) Estimate the reassessment interval as half the time required for the largest defect to grow to a critical size.
- (b) *Pipelines Operating Below 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating below 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is 7 calendar years. Operators may request a 6-month extension of the 7-calendar-year reassessment interval if the operator submits written notice to OPS in accordance with §192.18. The notice must include sufficient justification of the need for the extension. An operator must establish reassessment by at least one of the following:
- (1) Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in paragraph (a)(1) of this section except that the stress level referenced in paragraph (a)(1)(ii) of this section would be adjusted to reflect the lower operating stress level. If an established interval is more than 7 calendar years, an operator must conduct by the seventh calendar year of the interval either a confirmatory direct assessment in accordance with § 192.931, or a low stress reassessment in accordance with § 192.941.
 - (2) Reassessment by ECDA following the requirements in paragraph (a)(2) of this section.
 - (3) Reassessment by ICDA or SCCDA following the requirements in paragraph (a)(3) of this section.
 - (4) Reassessment by confirmatory direct assessment at 7-year intervals in accordance with § 192.931, with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this section by year 20 of the interval.
 - (5) Reassessment by the low stress assessment method at 7-year intervals in accordance with § 192.941 with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this section by year 20 of the interval.
 - (6) The following table sets forth the maximum reassessment intervals. Also refer to

Appendix E.ii for guidance on Assessment Methods and Assessment Schedule for Transmission Pipelines Operating Below 30% SMYS. In case of conflict between the rule and the guidance in the Appendix, the requirements of the rule control. An operator must comply with the following requirements in establishing a reassessment interval for a covered segment:

Maximum Reassessment Interval			
Assessment Method	Pipeline operating at or above 50% SMYS	Pipeline operating at or above 30% SMYS, up to 50% SMYS	Pipeline operating below 30% SMYS
Internal Inspection Tool, Pressure Test or Direct Assessment	10 years(*)	15 years(*)	20 years(**)
Confirmatory Direct Assessment	7 years	7 years	7 years
Low stress Reassessment	Not applicable	Not applicable	7 years + ongoing actions specified in § 192.941

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

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

§ 192.941 What is a low stress reassessment?

- (a) *General.* An operator of a transmission line that operates below 30% SMYS may use the following method to reassess a covered segment in accordance with § 192.939. This method of reassessment addresses the threats of external and internal corrosion. The operator must have conducted a baseline assessment of the covered segment in accordance with the requirements of §§ 192.919 and 192.921.
- (b) *External Corrosion.* An operator must take one of the following actions to address external corrosion on the low stress covered segment.
- (1) *Cathodically Protected Pipe.* To address the threat of external corrosion on cathodically protected pipe in a covered segment, an operator must perform an ~~electrical survey (i.e. indirect examination assessment on the covered segment tool/method)~~ at least o n c e every 7 calendar years ~~on the covered segment~~. ~~An operator must use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for the covered segment. This evaluation must consider, at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment. The indirect assessment must be conducted using one of the following~~

means: indirect examination method, such as a close interval survey; alternating current voltage gradient survey; direct current voltage gradient survey; or the equivalent of any of these methods. An operator must evaluate the cathodic protection and corrosion threat for the covered segment and include the results of each indirect assessment as part of the overall evaluation. This evaluation must also include, at a minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

- (2) *Unprotected Pipe or Cathodically Protected Pipe Where Electrical Surveys are Impractical.* ~~If an electrical survey is impractical on the covered segment an operator must~~ If an external corrosion assessment is impractical on the covered segment an operator must -
- (i) Conduct leakage surveys as required by § 192.706 at 4-month intervals; and
 - (ii) Every 18 months, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
- (c) *Internal Corrosion.* To address the threat of internal corrosion on a covered segment, an operator must -
- (1) Conduct a gas analysis for corrosive agents at least once each calendar year;
 - (2) Conduct periodic testing of fluids removed from the segment. At least once each calendar year test the fluids removed from each storage field that may affect a covered segment; and
 - (3) At least every seven (7) years, integrate data from the analysis and testing required by paragraphs (c)(1) - (c)(2) with applicable internal corrosion leak records, incident reports, safety-related condition reports, repair records, patrol records, exposed pipe reports, and test records, and define and implement appropriate remediation actions.

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

- (a) *Waiver from reassessment interval in limited situations.* In the following limited instances, OPS may allow a waiver from a reassessment interval required by § 192.939 if OPS finds a waiver would not be inconsistent with pipeline safety.
- (1) *Lack of internal inspection tools.* An operator who uses internal inspection as an assessment method may be able to justify a longer reassessment period for a covered segment if internal inspection tools are not available to assess the line pipe. To justify this, the operator must demonstrate that it cannot obtain the internal inspection tools within the required reassessment period and that the actions the operator is taking in the interim ensure the integrity of the covered segment.
 - (2) *Maintain product supply.* An operator may be able to justify a longer reassessment period for a covered segment if the operator demonstrates that it cannot maintain local product supply if it conducts the reassessment within the required interval.
- (b) *How to apply.* If one of the conditions specified in paragraph (a)(1) or (a)(2) of this section applies, an operator may seek a waiver of the required reassessment interval. An operator must apply for a waiver in accordance with 49 U.S.C. 60118(c), at least 180 days before the end of the required reassessment interval, unless local product supply issues make the period impractical. If local product supply issues make the period impractical, an operator must apply for the waiver as soon as the need for the waiver

becomes known.

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

§ 192.947 What records must an operator keep?

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

- (a) A written integrity management program in accordance with § 192.907;
- (b) Documents supporting the threat identification and risk assessment in accordance with § 192.917;
- (c) A written baseline assessment plan in accordance with § 192.919;
- (d) Documents to support any decision, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements;
- (e) Documents that demonstrate personnel have the required training, including a description of the training program, in accordance with § 192.915;
- (f) Schedule required by § 192.933 that prioritizes the conditions found during an assessment for evaluation and remediation, including technical justifications for the schedule.
- (g) Documents to carry out the requirements in §§ 192.923 through 192.929 for a direct assessment plan;
- (h) Documents to carry out the requirements in § 192.931 for confirmatory direct assessment;
- (i) Verification that an operator has provided any documentation or notification required by this subpart to be provided to OPS, and when applicable, a State authority with which OPS has an interstate agent agreement, and a State or local pipeline safety authority that regulates a covered pipeline segment within that State.

§ 192.949 [Removed and Reserved]

§ 192.951 Where does an operator file a report?

An operator must file any report required by this subpart to the Information Resources Manager through the online reporting system provided by PHMSA for electronic reporting in accordance with § 191.7 of this Code.

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?

- (a) *General.* Unless exempted in paragraph (b) of this section 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 this subpart.
- (b) *Exceptions.* This subpart does not apply to:
 - (1) Individual service lines directly connected to a production line or a gathering line other than a regulated onshore gathering line as determined in §192.8;
 - (2) Individual service lines directly connected to either a transmission or regulated gathering pipeline and maintained in accordance with §192.740(a) and (b); and
 - (3) Master meter systems.

§ 192.1005 What must a gas distribution operator (other than a 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 (including atmospheric corrosion), natural forces, excavation damage, other outside force damage, material or welds, equipment failure, incorrect operations, and other issues 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 incident and leak history, corrosion control records (including atmospheric corrosion 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 [Removed and Reserved]

§ 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 small LPG operator do to implement this subpart?

- (a) *General.* No later than August 2, 2011, a small LPG operator must develop and implement an IM program that includes a written IM plan as specified in paragraph (b) of this section. The IM program for these pipelines should reflect the relative simplicity of these types of pipelines.
- (b) *Elements.* A written integrity management plan must address, at a minimum, the following elements:
 - (1) *Knowledge.* The operator must demonstrate knowledge of its pipeline, which, to the extent known, should include the approximate location and material of its pipeline. The operator must identify additional information needed and provide a plan for gaining knowledge over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).
 - (2) *Identify threats.* The operator must consider, at minimum, the following categories of threats (existing and potential): corrosion (including atmospheric corrosion), natural forces, excavation damage, other outside force damage, material or weld failure, equipment failure, and incorrect operation.
 - (3) *Rank risks.* The operator must evaluate the risks to its pipeline and estimate the relative importance of each identified threat.
 - (4) *Identify and implement measures to mitigate risks.* The operator must determine and implement measures designed to reduce the risks from failure of its pipeline.
 - (5) *Measure performance, monitor results, and evaluate effectiveness.* The operator must monitor, as a performance measure, the number of leaks eliminated or repaired on its pipeline and their causes.
 - (6) *Periodic evaluation and improvement.* The operator must determine the appropriate period for conducting IM program evaluations based on the complexity of its pipeline and changes in factors affecting the risk of failure. An operator must re-evaluate its entire program at least every five years. The operator must consider the results of the performance monitoring in these evaluations.
- (c) *Records.* The operator must maintain, for a period of at least 10 years, the following records:
 - (1) A written IM plan in accordance with this section, including superseded IM plans;
 - (2) Documents supporting threat identification; and
 - (3) Documents showing the location and material of all piping and appurtenances that are installed after the effective date of the operator's IM program and, to the extent known, the location and material of all pipe and appurtenances that were existing on the effective date of the operator's program.

APPENDIX A TO PART 192 - RESERVED

APPENDIX B TO PART 192 - QUALIFICATION OF PIPE AND COMPONENTS

I. List of Specifications

A. Listed Pipe Specifications

API Spec 5L—Steel pipe, “Line Pipe” (incorporated by reference, see § 192.7).

ASTM A53/A53M—Steel pipe, “Standard Specification for Pipe, Steel Black and Hot-Dipped, Zinc-Coated, Welded and Seamless” (incorporated by reference, see § 192.7).

ASTM A106/A-106M—Steel pipe, “Standard Specification for Seamless Carbon Steel Pipe for High Temperature Service” (incorporated by reference, see § 192.7).

ASTM A333/A333M—Steel pipe, “Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service” (incorporated by reference, see § 192.7).

ASTM A381—Steel pipe, “Standard Specification for Metal-Arc-Welded Steel Pipe for Use with High-Pressure Transmission Systems” (incorporated by reference, see § 192.7).

ASTM A671/A671M—Steel pipe, “Standard Specification for Electric-Fusion-Welded Pipe for Atmospheric and Lower Temperatures” (incorporated by reference, see § 192.7).

ASTM A672/A672M-09—Steel pipe, “Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures” (incorporated by reference, see § 192.7).

ASTM A691/A691M-09—Steel pipe, “Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High Pressure Service at High Temperatures” (incorporated by reference, see § 192.7).

ASTM D2513 “Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings” (incorporated by reference, see § 192.7).

ASTM D 2517-00—Thermosetting plastic pipe and tubing, “Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings” (incorporated by reference, see § 192.7).

ASTM F2785-12 “Standard Specification for Polyamide 12 Gas Pressure Pipe, Tubing, and Fittings” (PA-12) (incorporated by reference, see § 192.7).

ASTM F2817-10 “Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair” (incorporated by reference, see § 192.7).

ASTM F2945-12a “Standard Specification for Polyamide 11 Gas Pressure Pipe, Tubing, and Fittings” (PA-11) (incorporated by reference, see § 192.7).

B. Other Listed Specifications for Components

ASME B16.40–2008 “Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems” (incorporated by reference, see § 192.7).

ASTM D2513 “Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings” (incorporated by reference, see § 192.7).

ASTM D 2517–00—Thermosetting plastic pipe and tubing, “Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings” (incorporated by reference, see § 192.7).

ASTM F2785–12 “Standard Specification for Polyamide 12 Gas Pressure Pipe, Tubing, and Fittings” (PA–12) (incorporated by reference, see § 192.7).

ASTM F2945–12a “Standard Specification for Polyamide 11 Gas Pressure Pipe, Tubing, and Fittings” (PA–11) (incorporated by reference, see § 192.7).

ASTM F1055–98 (2006) “Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing” (incorporated by reference, see § 192.7).

ASTM F1924–12 “Standard Specification for Plastic Mechanical Fittings for Use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing” (incorporated by reference, see § 192.7).

ASTM F1948–12 “Standard Specification for Metallic Mechanical Fittings for Use on Outside Diameter Controlled Thermoplastic Gas Distribution Pipe and Tubing” (incorporated by reference, see § 192.7).

ASTM F1973–13 “Standard Specification for Factory Assembled Anodeless Risers and Transition Fittings in Polyethylene (PE) and Polyamide 11 (PA 11) and Polyamide 12 (PA 12) Fuel Gas Distribution Systems” (incorporated by reference, see § 192.7).

ASTM F 2600–09 “Standard Specification for Electrofusion Type Polyamide–11 Fittings for Outside Diameter Controlled Polyamide–11 Pipe and Tubing” (incorporated by reference, see § 192.7).

ASTM F2145–13 “Standard Specification for Polyamide 11 (PA 11) and Polyamide 12 (PA12) Mechanical Fittings for Use on Outside Diameter Controlled Polyamide 11 and Polyamide 12 Pipe and Tubing” (incorporated by reference, see § 192.7).

ASTM F2767–12 “Specification for Electrofusion Type Polyamide–12 Fittings for Outside Diameter Controlled Polyamide–12 Pipe and Tubing for Gas Distribution” (incorporated by reference, see § 192.7).

ASTM F2817–10 “Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair” (incorporated by reference, see § 192.7).

APPENDIX C TO PART 192 - QUALIFICATION OF WELDERS FOR LOW STRESS LEVEL PIPE

I. Basic Test

The test is made on pipe 12 inches (305 millimeters) or less in diameter. The test weld must be made with the pipe in a horizontal fixed position so that the test weld includes at least one section of overhead position welding. The beveling, root opening and other details must conform to the specifications of the procedure under which the welder is being qualified. Upon completion, the test weld is cut into four coupons and subjected to a root bend test. If, as a result of this test, two or more of the four coupons develop a crack in the weld material or between the weld material and base metal, that is more than 1/8 inch (3.2 millimeters) long in any direction, the weld is unacceptable. Cracks that occur on the corner of the specimen during testing are not considered. A welder who successfully passes a butt-weld qualification test under this section shall be qualified to weld on all pipe diameters less than or equal to 12 inches.

II. Additional Tests for Welders of Service Line Connections to Mains

A service line connection fitting is welded to a pipe section with the same diameter as a typical main. The weld is made in the same position as it is made in the field. The weld is unacceptable if it shows a serious undercutting or if it has rolled edges. The weld is tested by attempting to break the fitting off the run pipe. The weld is unacceptable if it breaks and shows incomplete fusion, overlap, or poor penetration at the junction of the fitting and run pipe.

III. Periodic Tests for Welders of Small Service Lines

Two samples of the welder's work, each about 8 inches (203 millimeters) long with the weld located approximately in the center, are cut from steel service line and tested as follows:

- (1) One sample is centered in a guided bend testing machine and bent to the contour of the die for a distance of 2 inches (51 millimeters) on each side of the weld. If the sample shows any breaks or cracks after removal from the bending machine, it is unacceptable.
- (2) The ends of the second sample are flattened and the entire joint subjected to a tensile strength test. If failure occurs adjacent to or in the weld metal, the weld is unacceptable. If a tensile strength testing machine is not available, this sample must also pass the bending test prescribed in Subparagraph (1) of this paragraph.

APPENDIX D TO PART 192 - CRITERIA FOR CATHODIC PROTECTION AND DETERMINATION OF MEASUREMENTS

I. Criteria for Cathodic Protection

A. *Steel, cast iron, and ductile iron structures*

- (1) A negative (cathodic) voltage of at least 0.85 volt, with reference to a saturated copper-copper sulfate half-cell. Determination of this voltage must be made with the protective current applied, and in accordance with Sections II and IV of this Appendix.
- (2) A negative (cathodic) voltage shift of at least 300 millivolts. Determination of this voltage shift must be made with the protective current applied, and in accordance with Sections II and IV of this Appendix. This criterion of voltage shift applies to structures not in contact with metal of different anodic potentials.
- (3) A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with Sections III and IV of this Appendix.
- (4) A voltage at least as negative (cathodic) as that originally established at the beginning of the Tafel segment of the E-log-I curve. This voltage must be measured in accordance with Section IV of this appendix.
- (5) A net protective current from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.

B. *Aluminum structures*

- (1) Except as provided in Subparagraphs (3) and (4) of this paragraph, a minimum negative (cathodic) voltage shift of 150 millivolts, produced by the application of protective current. The voltage shift must be determined in accordance with Sections II and IV of this Appendix.
- (2) Except as provided in Subparagraphs (3) and (4) of this paragraph, a minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with Sections III and IV of this Appendix.
- (3) Notwithstanding the alternative minimum criteria in Subparagraphs (1) and (2) of this paragraph, aluminum, if cathodically protected at voltages in excess of 1.20 volts as measured with reference to a copper-copper sulfate half-cell, in accordance with Section IV of this appendix, and compensated for the voltage (IR) drops other than those across the structure-electrolyte boundary, may suffer corrosion resulting from the buildup of alkali on the metal surface. A voltage in excess of 1.20 volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.
- (4) Since aluminum may suffer from corrosion under high pH conditions, and since application of cathodic protection tends to increase the pH at the metal surface, careful investigation or testing must be made before applying cathodic protection to stop pitting attack on aluminum structures in environments with a natural pH in excess of 8.

C. *Copper structures*

A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with Sections III and IV of this Appendix.

D. Metals of different anodic potentials

A negative (cathodic) voltage, measured in accordance with Section IV of this appendix, equal to that required for the most anodic metal in the system must be maintained. If amphoteric structures are involved that could be damaged by high alkalinity covered by Subparagraphs (3) and (4) of paragraph B of this section, they must be electrically isolated with insulating flanges, or the equivalent.

II. Interpretation of Voltage Measurement

Voltage (IR) drops other than those across the structure-electrolyte boundary must be considered for valid interpretation of the voltage measurement in paragraphs A(1) and (2) and paragraph B(1) of Section I of this appendix.

III. Determination of Polarization Voltage Shift

The polarization voltage shift must be determined by interrupting the protective current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay in paragraphs A(3), B(2), and C of Section I of this appendix.

IV. Reference Half Cells

- A.** Except as provided in paragraphs B and C of this section, negative (cathodic) voltage must be measured between the structure surface and a saturated copper-copper sulfate half cell contacting the electrolyte.
- B.** Other standard reference half cells may be substituted for the saturated copper-copper sulfate half-cell. Two commonly used reference half cells are listed below along with their voltage equivalent to -0.85 volt as referred to a saturated copper- copper sulfate half cell:
 - (1) Saturated KCl calomel half cell: -0.78 volt.
 - (2) Silver-silver chloride half-cell used in sea water: -0.80 volt.
- C.** In addition to the standard reference half cells, an alternate metallic material or structure may be used in place of the saturated copper sulfate half- cell if its potential stability is assured and if its voltage equivalent referred to a saturated copper-copper sulfate half- cell is established.

APPENDIX E TO PART 192 - GUIDANCE ON DETERMINING HIGH CONSEQUENCE AREAS AND ON CARRYING OUT REQUIREMENTS IN THE INTEGRITY MANAGEMENT RULE

I. Guidance on Determining a High Consequence Area

To determine which segments of an operator's transmission pipeline system are covered for purposes of the integrity management program requirements, an operator must identify the high consequence areas. An operator must use method (1) or (2) from the definition in § 192.903 to identify a high consequence area. An operator may apply one method to its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system. (Refer to figure E.1.A for a diagram of a high consequence area).

Determining High Consequence Area

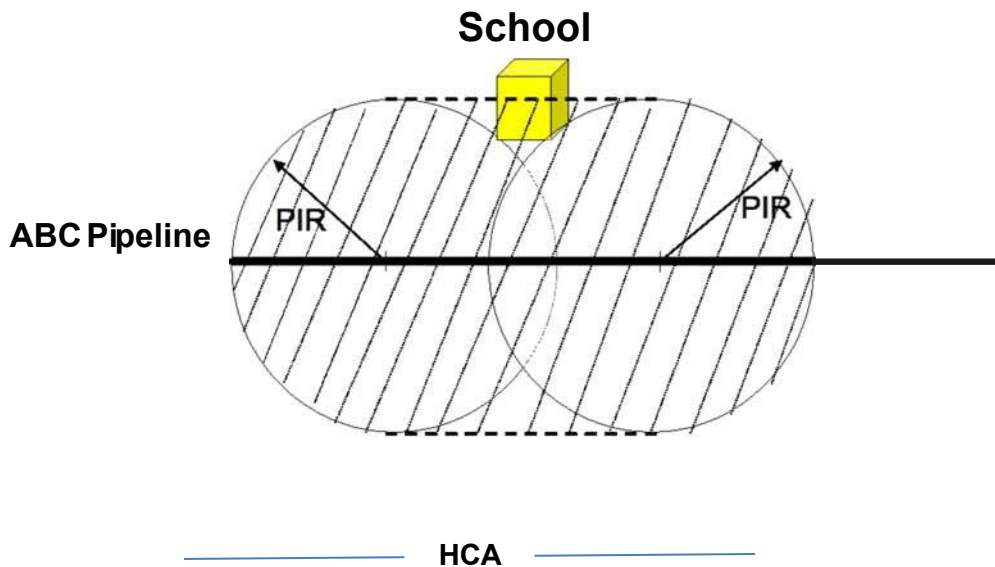


Figure E.1.A

II. Guidance on Assessment Methods and Additional Preventive and Mitigative Measures for Transmission Pipelines

- (a) Table E.11.1 gives guidance to help an operator implement requirements on additional preventive and mitigative measures for addressing time dependent and independent threats for a transmission pipeline operating below 30% SMYS not in an HCA (i.e. outside of potential impact circle) but located within a Class 3 or Class 4 Location.
- (b) Table E.11.2 gives guidance to help an operator implement requirements on assessment methods for addressing time dependent and independent threats for a transmission pipeline in an HCA.
- (c) Table E.11.3 gives guidance on preventative & mitigative measures addressing time dependent and independent threats for transmission pipelines that operate below 30% SMYS, in HCAs.

Table E.II.1

Preventive and Mitigative Measures for Transmission Pipelines Operating Below 30% SMYS not in an HCA but in a Class 3 or Class 4 Location

(Column 1) Threat	Existing 192 Requirements		(Column 4) Additional (to 192 requirements) Preventive and Mitigative
External Corrosion.....	455-(Gen. Post 1971), 457-(Gen. Pre-1971). 459-(Examination), 461-(Ext. coating). 463-(CP), 465-(Monitoring). 467-(Elect isolation), (469-Test stations). 471-(Test leads), 473- (Interference). 479-(Atmospheric), 481- (Atmospheric). 485-(Remedial), 705-(Patrol). 706-(Leak survey), 711 -(Repair-gen.) 717-(Repair-perm.)	603 – (Gen Operation)..... 613 - (Surveillance).....	<ul style="list-style-type: none"> • For Cathodically Protected Transmission Pipeline: • Perform semi-annual leak surveys. • For Unprotected Transmission Pipelines or for Cathodically Protected Pipe where indirect assessments are impractical. Electrical Surveys are Impractical: • Perform quarterly leak surveys
Internal Corrosion	475-(Gen IC), 477-(IC monitoring). 485-(Remedial), 705-(Patrol). 706-(Leak survey), 711-(Repair-gen.). 717-(Repair - perm.).	53(a)-(Materials). 603-(Gen. Oper'n). 613-(Surveillance).	<ul style="list-style-type: none"> • Perform quarterly leak surveys. Perform semi-annual leak surveys.

<p>3rd Party Damage</p>	<p>103-(Gen. Design), 111-(Design factor). 317-(Hazard prot), 327-(Cover). 614-(Dam. Prevent), 616-(Public education). 705-(Patrol), 707-(Line markers). 711 (Repair-gen.), 717-(Repair-perm.).</p>	<p>615 (Emerg. Plan)</p>	<ul style="list-style-type: none"> •Participation in state one-call system, •Use of qualified operator employees and contractors to perform marking and locating of buried structures and in direct supervision of excavation work, AND •Either monitoring of excavations near operator's transmission pipelines, or bi-monthly patrol of transmission pipelines in class 3 and 4 locations. Any indications of unreported construction activity would require a follow up investigation to determine if mechanical damage occurred.
------------------------------------	---	--------------------------	---

Table E.II.2

**Assessment Requirements for Transmission Pipelines in HCAs
(Re-assessment intervals are maximum allowed)**

[table on next page]

Re-Assessment Requirements (see Note 3)

Note 1: Operator may choose to utilize CDA at year 14, then utilize ILI, Pressure Test, or DA at year 15 as allowed under ASME B31.8S.
 Note 2: Operator may choose to utilize CDA at year 7 and 14 in lieu of P&M.
 Note 3: Operator may utilize "other

	<u>Re-Assessment Requirements (see Note 3)</u>					
	<u>At or above 50% SMYS</u>		<u>At or above 30% SMYS</u>		<u>Below 30% SMYS</u>	
<u>Baseline Assessment Method (see Note 3)</u>	<u>Max Re-Assessment Interval</u>	<u>Assessment Method</u>	<u>Max Re-Assessment Interval</u>	<u>Assessment Method</u>	<u>Max Re-Assessment Interval</u>	<u>Assessment Method</u>
<u>Pressure Testing</u>	<u>7</u>	<u>CDA</u>	<u>7</u>	<u>CDA</u>	<u>Ongoing</u>	<u>Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)</u>
	<u>10</u>	<u>Pressure Test or ILI or DA</u>				
		<u>Repeat inspection cycle every 10 years</u>	<u>15 (see Note 1)</u>	<u>Pressure Test or ILI or DA (see Note 1)</u>		
				<u>Repeat inspection cycle every 15 years</u>		
				<u>20</u>		
			<u>Repeat inspection cycle every 20 years</u>			
<u>In-Line Inspection</u>	<u>7</u>	<u>CDA</u>	<u>7</u>	<u>CDA</u>	<u>Ongoing</u>	<u>Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)</u>
	<u>10</u>	<u>ILI or DA or Pressure Test</u>				
		<u>Repeat inspection cycle every 10 years</u>	<u>15 (see Note 1)</u>	<u>ILI or DA or Pressure Test (see Note 1)</u>		
				<u>Repeat inspection cycle every 15 years</u>		
				<u>20</u>		
			<u>Repeat inspection cycle every 20 years</u>			
<u>Direct Assessment</u>	<u>7</u>	<u>CDA</u>	<u>7</u>	<u>CDA</u>	<u>Ongoing</u>	<u>Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)</u>
	<u>10</u>	<u>DA or ILI or Pressure Test</u>				
		<u>Repeat inspection cycle every 10 years</u>	<u>15 (see Note 1)</u>	<u>DA or ILI or Pressure Test (see Note 1)</u>		
				<u>Repeat inspection cycle every 15 years</u>		
				<u>20</u>	<u>DA or ILI or Pressure Test</u>	
			<u>Repeat inspection cycle every 20 years</u>			

technology that an operator demonstrates can provide an equivalent understanding of the condition of line pipe."

~~Note 1: Operator may choose to utilize CDA at year 14, then utilize ILL, Pressure Test, or DA at year 15 as allowed under ASME B31.8S — Note 2: Operator may choose to utilize CDA at year 7 and 14 in lieu of P&M
Note 3: Operator may utilize other technology that an operator demonstrates can provide an equivalent understanding of the condition of line pipe.~~

Operator may _____ technology that an operator demonstrates can provide an equivalent understanding of the condition of line

**Table E.II.3
Preventative & Mitigative Measures addressing Time Dependent and Independent Threats for
Transmission Pipelines that Operate Below 30% SMYS, in HCAs**

Threat	Existing 192 Requirements		Additional (to 192 requirements) Preventive & Mitigative Measures
	Primary	Secondary	
<u>External Corrosion</u>	<u>455 – (Gen. Post 1971)</u> <u>457 – (Gen. pre1971)</u> <u>459 - (Examination)</u> <u>461 – (Ext. coating)</u> <u>463 - (CP)</u> <u>465 - (Monitoring)</u> <u>467 – (Elect isolation)</u>	 <u>603 - (Gen Oper)</u> <u>613 - (Surveil)</u>	<u>For Cathodically protected Trmn. Pipelines</u> <u>•Perform an electrical survey (i.e. indirect examination tool/method) at least every 7 years. Results are to be utilized as part of an overall evaluation of the CP system and corrosion threat for the covered segment. Evaluation shall include consideration of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.</u>
<u>External Corrosion</u>	<u>469 – (Test stations)</u> <u>471 - (Test leads)</u> <u>473 - (Interference)</u> <u>479 - (Atmospheric)</u> <u>481 – (Atmospheric)</u> <u>485 - (Remedial)</u> <u>705 - (Patrol)</u> <u>706 - (Leak survey)</u> <u>711 - (repair - gen.)</u> <u>717 - (Repair perm.)</u>	 	<u>For Unprotected Trmn. Pipelines or for Cathodically protected Pipe where Electrical Surveys are Impracticable</u> <u>•Conduct quarterly leak surveys AND</u> <u>•Every 1 1/2 years, determine areas of active corrosion by evaluation of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.</u>
<u>Internal Corrosion</u>	<u>475 - (Gen IC)</u> <u>477 - (IC monitoring)</u> <u>485 - (Remedial)</u> <u>705 - (Patrol)</u> <u>706 – (Leak survey)</u> <u>711 – (repair - gen.)</u> <u>717 - (Repair perm.)</u>	<u>53 (a) - (Materials)</u> <u>603 - (Gen Oper)</u> <u>613 - (Surveil)</u>	<u>•Obtain and review gas analysis data each calendar year for corrosive agents from transmission pipelines in HCAs,</u> <u>•Periodic testing of fluid removed from pipelines. Specifically, once each calendar year from each storage field that may affect transmission pipelines in HCAs, AND</u> <u>•At least every 7 years, integrate data obtained with applicable internal corrosion leak records, incident reports, safety related condition reports, repair records, patrol records, exposed pipe reports, and test records.</u>

<u>3rd Party Damage</u>	<u>103 - (Gen. Design)</u> <u>111 - (Design factor)</u> <u>317 - (Hazard prot)</u> <u>327 - (cover)</u> <u>614 - (Dam. Prevent)</u> <u>616 - (Public educat)</u> <u>705 - (Patrol)</u> <u>707 - (Line markers)</u> <u>711 - (repair - gen.)</u> <u>717 - (Repair-perm.)</u>	<u>615 - (Emerg Plan)</u>	<ul style="list-style-type: none"> •<u>Participation in state one-call system.</u> •<u>Use of qualified operator employees and contractors to perform making and locating of buried structures and in direct supervision of excavation work, AND</u> •<u>Either monitoring of excavations near operator's transmission pipelines, or bi-monthly patrol of transmission pipelines in HCAs or class 3 or 4 locations. Any indications of unreported construction activity would require a follow up investigation to determine if mechanical damage occurred.</u>
-----------------------------	--	-------------------------------	--

APPENDIX F TO PART 192 - CRITERIA FOR CONDUCTING INTEGRITY ASSESSMENTS USING GUIDED WAVE ULTRASONIC TESTING (GWUT)

This appendix defines criteria which must be properly implemented for use of guided wave ultrasonic testing (GWUT) as an integrity assessment method. Any application of GWUT that does not conform to these criteria is considered “other technology” as described by §§ 192.710(c)(7), 192.921(a)(7), and 192.937(c)(7), for which OPS must be notified 90 days prior to use in accordance with §§ 192.921(a)(7) or 192.937(c)(7). GWUT in the “Go–No Go” mode means that all indications (wall loss anomalies) above the testing threshold (a maximum of 5% of ~~cross-sectional~~cross-sectional area (CSA) sensitivity) be directly examined, in-line tool inspected, pressure tested, or replaced prior to completing the integrity assessment on the carrier pipe.

- I. *Equipment and Software: Generation.* The equipment and the computer software used are critical to the success of the inspection. Computer software for the inspection equipment must be reviewed and updated, as required, on an annual basis, with intervals not to exceed 15 months, to support sensors, enhance functionality, and resolve any technical or operational issues identified.
- II. *Inspection Range.* The inspection range and sensitivity are set by the signal to noise (S/N) ratio but must still keep the maximum threshold sensitivity at 5% cross sectional area (CSA). A signal that has an amplitude that is at least twice the noise level can be reliably interpreted. The greater the S/N ratio the easier it is to identify and interpret signals from small changes. The signal to noise ratio is dependent on several variables such as surface roughness, coating, coating condition, associated pipe fittings (T's, elbows, flanges), soil compaction, and environment. Each of these affects the propagation of sound waves and influences the range of the test. It may be necessary to inspect from both ends of the pipeline segment to achieve a full inspection. In general, the inspection range can approach 60 to 100 feet for a 5% CSA, depending on field conditions.
- III. *Complete Pipe Inspection.* To ensure that the entire pipeline segment is assessed there should be at least a 2 to 1 signal to noise ratio across the entire pipeline segment that is inspected. This may require multiple GWUT shots. Double-ended inspections are expected. These two inspections are to be overlaid to show the minimum 2 to 1 S/N ratio is met in the middle. If possible, show the same near or midpoint feature from both sides and show an approximate 5% distance overlap.
- IV. *Sensitivity.* The detection sensitivity threshold determines the ability to identify a ~~cross sectional~~cross-sectional change. The maximum threshold sensitivity cannot be greater than 5% of the ~~cross-sectional~~cross-sectional area (CSA).

The locations and estimated CSA of all metal loss features in excess of the detection threshold must be determined and documented.

All defect indications in the “Go-No-Go” mode above the 5% testing threshold must be directly examined, in-line inspected, pressure tested, or replaced prior to completing the integrity assessment.

- V. *Wave Frequency.* Because a single wave frequency may not detect certain defects, a minimum of three frequencies must be run for each inspection to determine the best frequency for characterizing indications. The frequencies used for the inspections must be documented and must be in the range specified by the manufacturer of the equipment.

- VI. *Signal or Wave Type: Torsional and Longitudinal.* Both torsional and longitudinal waves must be used, and use must be documented.
- VII. *Distance Amplitude Correction (DAC) Curve and Weld Calibration.* The distance amplitude correction curve accounts for coating, pipe diameter, pipe wall and environmental conditions at the assessment location. The DAC curve must be set for each inspection as part of establishing the effective range of a GWUT inspection. DAC curves provide a means for evaluating the cross-sectional area change of reflections at various distances in the test range by assessing signal to noise ratio. A DAC curve is a means of taking apparent attenuation into account along the time base of a test signal. It is a line of equal sensitivity along the trace which allows the amplitudes of signals at different axial distances from the collar to be compared.
- VIII. *Dead Zone.* The dead zone is the area adjacent to the collar in which the transmitted signal blinds the received signal, making it impossible to obtain reliable results. Because the entire line must be inspected, inspection procedures must account for the dead zone by requiring the movement of the collar for additional inspections. An alternate method of obtaining valid readings in the dead zone is to use B- scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.
- IX. *Near Field Effects.* The near field is the region beyond the dead zone where the receiving amplifiers are increasing in power, before the wave is properly established. Because the entire line must be inspected, inspection procedures must account for the near field by requiring the movement of the collar for additional inspections. An alternate method of obtaining valid readings in the near field is to use B- scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.
- X. *Coating Type.* Coatings can have the effect of attenuating the signal. Their thickness and condition are the primary factors that affect the rate of signal attenuation. Due to their variability, coatings make it difficult to predict the effective inspection distance. Several coating types may affect the GWUT results to the point that they may reduce the expected inspection distance. For example, concrete coated pipe may be problematic when well bonded due to the attenuation effects. If an inspection is done and the required sensitivity is not achieved for the entire length of the pipe, then another type of assessment method must be utilized.
- XI. *End Seal.* When assessing cased carrier pipe with GWUT, operators must remove the end seal from the casing at each GWUT test location to facilitate visual inspection. Operators must remove debris and water from the casing at the end seals. Any corrosion material observed must be removed, collected and reviewed by the operator's corrosion technician. The end seal does not interfere with the accuracy of the GWUT inspection but may have a dampening effect on the range.
- XII. *Weld Calibration to set DAC Curve.* Accessible welds, along or outside the pipeline segment to be inspected, must be used to set the DAC curve. A weld or welds in the access hole (secondary area) may be used if welds along the pipeline segment are not accessible. In order to use these welds in the secondary area, sufficient distance must be allowed to account for the dead zone and near field. There must not be a weld between the transducer collar and the calibration weld. A conservative estimate of the predicted amplitude for the weld is 25% CSA (cross sectional area) and can be used if welds are not accessible. Calibrations (setting of the DAC curve) should be on pipe with similar properties such as wall thickness and coating. If the actual weld cap height is different from the assumed weld cap height, the estimated CSA may be inaccurate and

adjustments to the DAC curve may be required. Alternative means of calibration can be used if justified by a documented engineering analysis and evaluation.

XIII. *Validation of Operator Training.* Pipeline operators must require all guided wave service providers to have equipment-specific training and experience for all GWUT Equipment Operators which includes training for:

- Equipment operation,
- field data collection, and
- data interpretation on cased and buried pipe.

Only individuals who have been qualified by the manufacturer or an independently assessed evaluation procedure similar to ISO 9712 (Sections: 5 Responsibilities; 6 Levels of Qualification; 7 Eligibility; and 10 Certification), as specified above, may operate the equipment. A senior-level GWUT equipment operator with pipeline specific experience must provide onsite oversight of the inspection and approve the final reports. A senior-level GWUT equipment operator must have additional training and experience, including training specific to cased and buried pipe, with a quality control program which that conforms to Section 12 of ASME B31.8S (for availability, see § 192.7).

XIV. Training and Experience Minimums for Senior Level GWUT Equipment Operators:

- Equipment Manufacturer's minimum qualification for equipment operation and data collection with specific endorsements for casings and buried pipe
- Training, qualification and experience in testing procedures and frequency determination
- Training, qualification and experience in conversion of guided wave data into pipe features and estimated metal loss (estimated cross-sectional area loss and circumferential extent)
- Equipment Manufacturer's minimum qualification with specific endorsements for data interpretation of anomaly features for pipe within casings and buried pipe.

XV. *Equipment: Traceable from vendor to inspection company.* An operator must maintain documentation of the version of the GWUT software used and the serial number of the other equipment such as collars, cables, etc., in the report.

XVI. *Calibration Onsite.* The GWUT equipment must be calibrated for performance in accordance with the manufacturer's requirements and specifications, including the frequency of calibrations. A diagnostic check and system check must be performed on-site each time the equipment is relocated to a different casing or pipeline segment. If on-site diagnostics show a discrepancy with the manufacturer's requirements and specifications, testing must cease until the equipment can be restored to manufacturer's specifications.

XVII. *Use on Shorted Casings (direct or electrolytic).* GWUT may not be used to assess shorted casings. GWUT operators must have operations and maintenance procedures (see § 192.605) to address the effect of shorted casings on the GWUT signal. The equipment operator must clear any evidence of interference, other than some slight dampening of the GWUT signal from the shorted casing, according to their operating and maintenance procedures. All shorted casings found while conducting GWUT inspections must be addressed by the operator's standard operating procedures.

XVIII. *Direct examination of all indications above the detection sensitivity threshold. The use of GWUT in the “Go-No Go” mode requires that all indications –(wall loss anomalies) above the testing threshold (5% of CSA sensitivity) be directly examined (or replaced) prior to completing the integrity assessment on the cased carrier pipe or other GWUT application. If this cannot be accomplished, then alternative methods of assessment (such as hydrostatic pressure tests or ILI) must be utilized.*

XIX. *Timing of direct examination of all indications above the detection sensitivity threshold. Operators must either replace or conduct direct examinations of all indications identified above the detection sensitivity threshold according to the table below. Operators must conduct leak surveys and reduce operating pressure as specified until the pipe is replaced or direct examinations are completed.*

Required Response to GWUT Indications			
GWUT criterion	Operating pressure less than or equal to 30% SMYS	Operating pressure over 30 and less than or equal to 50 SMYS	Operating pressure over 50% SMYS
Over the detection sensitivity threshold (maximum of 5% CSA)	Replace or direct examination within 12 months, and instrumented leak survey once every 30 calendar days	Replace or direct examination within 6 months, instrumented leak survey once every 30 calendar days, and maintain MAOP below the operating pressure at time of discovery	Replace or direct examination within 6 months, instrumented leak survey once every 30 calendar days, and reduce MAOP to 80% of operating pressure at time of discovery.

PART 193 - LIQUEFIED NATURAL GAS FACILITIES:
FEDERAL SAFETY STANDARDS

SUBPART A - GENERAL

~~§ 193.2001 Scope of Part~~

- ~~(a) This part prescribes safety standards for LNG facilities used in the transportation of gas by pipeline that is subject to the pipeline safety laws (49 U.S.C. 60101 et seq.) and Part 192 of this chapter.~~
- ~~(b) This part does not apply to:
 - ~~(1) LNG facilities used by ultimate consumers of LNG or natural gas.~~
 - ~~(2) LNG facilities used in the course of natural gas treatment or hydrocarbon extraction which do not store LNG.~~
 - ~~(3) In the case of a marine cargo transfer system and associated facilities, any matter other than siting pertaining to the system or facilities between the marine vessel and the last manifold (or in the absence of a manifold, the last valve) located immediately before a storage tank.~~
 - ~~(4) Any LNG facility located in navigable waters (as defined in Section 3(8) of the Federal Power Act (16 U.S.C. 796(8)).~~~~

~~§ 193.2003 [Reserved]~~

~~§ 193.2005 Applicability~~

- ~~(a) Regulations in this part governing siting, design, installation, or construction of LNG facilities (including material incorporated by reference in these regulations) do not apply to LNG facilities in existence or under construction when the regulations go into effect.~~
- ~~(b) If an existing LNG facility (or facility under construction before March 31, 2000) is replaced, relocated or significantly altered after March 31, 2000, the facility must comply with the applicable requirements of this part governing siting, design, installation, and construction, except that:
 - ~~(1) The siting requirements apply only to LNG storage tanks that are significantly altered by increasing the original storage capacity or relocated, and~~
 - ~~(2) To the extent compliance with the design, installation, and construction requirements would make the replaced, relocated, or altered facility incompatible with the other facilities or would otherwise be impractical, the replaced, relocated, or significantly altered facility may be designed, installed, or constructed in accordance with the original specifications for the facility, or in another manner subject to the approval of the Administrator.~~~~

~~§ 193.2007 Definitions~~

As used in this part:

~~Administrator~~ means the Administrator, Pipeline and Hazardous Materials Safety Administration or

his or her delegate.

~~**Ambient vaporizer** means a vaporizer which derives heat from naturally occurring heat sources, such as the atmosphere, sea water, surface waters, or geothermal waters.~~

~~**Cargo transfer system** means a component, or system of components functioning as a unit, used exclusively for transferring hazardous fluids in bulk between a tank car, tank truck, or marine vessel and a storage tank.~~

~~**Component** means any part, or system of parts functioning as a unit, including, but not limited to, piping, processing equipment, containers, control devices, impounding systems, lighting, security devices, fire control equipment, and communication equipment, whose integrity or reliability is necessary to maintain safety in controlling, processing, or containing a hazardous fluid.~~

~~**Container** means a component other than piping that contains a hazardous fluid.~~

~~**Control system** means a component, or system of components functioning as a unit, including control valves and sensing, warning, relief, shutdown, and other control devices, which is activated either manually or automatically to establish or maintain the performance of another component.~~

~~**Controllable emergency** means an emergency where reasonable and prudent action can prevent harm to people or property.~~

~~**Design pressure** means the pressure used in the design of components for the purpose of determining the minimum permissible thickness or physical characteristics of its various parts. When applicable, static head shall be included in the design pressure to determine the thickness of any specific part.~~

~~**Determine** means make an appropriate investigation using scientific methods, reach a decision based on sound engineering judgment, and be able to demonstrate the basis of the decision.~~

~~**Dike** means the perimeter of an impounding space forming a barrier to prevent liquid from flowing in an unintended direction.~~

~~**Emergency** means a deviation from normal operation, a structural failure, or severe environmental conditions that probably would cause harm to people or property.~~

~~**Exclusion zone** means an area surrounding an LNG facility in which an operator or government agency legally controls all activities in accordance with § 193.2057 and § 193.2059 for as long as the facility is in operation.~~

~~**Fail-safe** means a design feature which will maintain or result in a safe condition in the event of malfunction or failure of a power supply, component, or control device.~~

~~**g** means the standard acceleration of gravity of 9.806 meters per second (32.17 feet per second).~~

~~**Gas**, except when designated as inert, means natural gas, other flammable gas, or gas which is toxic or corrosive.~~

~~**Hazardous fluid** means gas or hazardous liquid.~~

~~**Hazardous liquid** means LNG or a liquid that is flammable or toxic.~~

~~**Heated vaporizer** means a vaporizer which derives heat from other than naturally occurring heat sources.~~

~~**Impounding space** means a volume of space formed by dikes and floors which is designed to confine a spill of hazardous liquid.~~

~~**Impounding system** includes an impounding space, including dikes and floors for conducting the flow of spilled hazardous liquids to an impounding space.~~

~~**Liquefied natural gas** or **LNG** means natural gas or synthetic gas having methane (CH⁴) as its major constituent which has been changed to a liquid.~~

~~**LNG facility** means a pipeline facility that is used for liquefying natural gas or synthetic gas or transferring, storing, or vaporizing liquefied natural gas.~~

~~**LNG plant** means an LNG facility or system of LNG facilities functioning as a unit.~~

~~**m** means a volumetric unit which is one cubic meter, 6.2898 barrels, 35.3147 ft. , or 264.1720 U.S. gallons, each volume being considered as equal to the other.~~

~~**Maximum allowable working pressure** means the maximum gage pressure permissible at the top of the equipment, containers or pressure vessels while operating at design temperature.~~

~~**Normal operation** means functioning within ranges of pressure, temperature, flow, or other operating criteria required by this part.~~

~~**Operator** means a person who owns or operates an LNG facility.~~

~~**Person** means any individual, firm, joint venture, partnership, corporation, association, state, municipality, cooperative association, or joint stock association and includes any trustee, receiver, assignee, or personal representative thereof.~~

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

~~**Piping** means pipe, tubing, hoses, fittings, valves, pumps, connections, safety devices or related components for containing the flow of hazardous fluids.~~

~~**Storage tank** means a container for storing a hazardous fluid.~~

~~**Transfer piping** means a system of permanent and temporary piping used for transferring hazardous fluids between any of the following: Liquefaction process facilities, storage tanks, vaporizers, compressors, cargo transfer systems, and facilities other than pipeline facilities.~~

~~**Transfer system** includes transfer piping and cargo transfer system.~~

~~**Vaporization** means an addition of thermal energy changing a liquid to a vapor or gaseous state.~~

~~**Vaporizer** means a heat transfer facility designed to introduce thermal energy in a controlled manner for changing a liquid to a vapor or gaseous state.~~

~~**Waterfront LNG plant** means an LNG plant with docks, wharves, piers, or other structures in, on, or immediately adjacent to the navigable waters of the United States or Puerto Rico and any shore area immediately adjacent to those waters to which vessels may be secured and at which LNG cargo operations may be conducted.~~

~~§ 193.2009 Rules of Regulatory Construction~~

~~(a) — As used in this part:~~

- ~~(1) — **Includes** means including but not limited to;~~
- ~~(2) — **May** means is permitted to or is authorized to;~~
- ~~(3) — **May not** means is not permitted to or is not authorized to; and~~
- ~~(4) — **Shall** or **must** is used in the mandatory and imperative sense.~~

~~(b) In this part:~~

- ~~(1) Words importing the singular include the plural; and~~
- ~~(2) Words importing the plural include the singular.~~

~~§ 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.~~

~~§ 193.2013 What documents are incorporated by reference partly or wholly in this part?~~

~~(a) This part prescribes standards, or portions thereof, incorporated by reference into this part with the approval of the Director of the Federal Register in 5 U.S.C. 552(a) and 1 CFR part 51. The materials listed in this section have the full force of law. To enforce any edition other than that specified in this section, PHMSA must publish a notice of change in the Federal Register.~~

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

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

~~(ii) The National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202-741-6030 or go to the NARA Web site at: <http://www.archives.gov/federal-register/code-of-federal-regulations/ibr/locations.html>.~~

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

~~(b) American Gas Association (AGA), 400 North Capitol Street NW., Washington, DC 20001, and phone: 202-824-7000, Web site: <http://www.aga.org/>.~~

~~(1) American Gas Association, "Purging Principles and Practices," 3rd edition, June 2001, (Purging Principles and Practices), IBR approved for §§ 193.2513(b) and (c), 193.2517, and 193.2615(a).~~

~~(2) [Reserved]~~

~~(c) American Petroleum Institute (API), 1220 L Street NW., Washington, DC 20005, and phone: 202-682-8000, Web site: <http://api.org/>.~~

~~(1) API Standard 620 "Design and Construction of Large, Welded, Low-pressure Storage Tanks," 11th edition, February 2008 (including addendum 1 (March 2009), addendum 2 (August 2010), and addendum 3 (March 2012)), (API Std 620), IBR approved for §§ 193.2101(b); 193.2321(b).~~

~~(2) [Reserved]~~

~~(d) American Society of Civil Engineers (ASCE), 1801 Alexander Bell Drive, Reston, VA~~

~~20191, (800) 548-2723, 703-295-6300 (international), Website: <http://www.asce.org>.~~

- ~~(1) ASCE/SEI 7-05, "Minimum Design Loads for Buildings and Other Structures" 2005 edition including supplement No. 1 and Errata, (ASCE/SEI 7-05), IBR approved for § 193.2067(b).~~
- ~~(2) [Reserved]~~
- ~~(e) ASME International (ASME), Three Park Avenue, New York, NY 10016. 800-843-2763 (U.S./Canada), Web site: <http://www.asme.org/>.~~
 - ~~(1) ASME Boiler & Pressure Vessel Code, Section VIII, Division 1: "Rules for Construction of Pressure Vessels," 2007 edition, July 1, 2007, (ASMEBPVC, Section VIII, Division 1), IBR approved for § 193.2321(a).~~
 - ~~(2) [Reserved]~~
- ~~(f) Gas Technology Institute (GTI), formerly the Gas Research Institute (GRI), 1700 S. Mount Prospect Road, Des Plaines, IL 60018, phone: 847-768-0500, Web site: <http://www.gastechnology.org/>.~~
 - ~~(1) GRI 96/039.5, "Evaluation of Mitigation Methods for Accidental LNG Releases, Volume 5: Using FEM3A for LNG Accident Consequence Analyses" April 1997, (GRI 96/0396.5), IBR approved for § 193.2059(a).~~
 - ~~(2) GTI 04/0032 LNGFIRE3: "A Thermal Radiation Model for LNG Fires" March 2004, (GTI 04/0032 LNGFIRE3), IBR approved for § 193.2057(a).~~
 - ~~(3) GTI 04/0049 "LNG Vapor Dispersion Prediction with the DEGADIS 2.1: Dense Gas Dispersion Model for LNG Vapor Dispersion," 2004, (GTI 04/0049), IBR approved for § 193.2059(a).~~
- ~~(g) National Fire Protection Association (NFPA), 1 Batterymarch Park, Quincy, MA, 02169 phone: 617-984-7275, Web site: <http://www.nfpa.org/>.~~
 - ~~(1) NFPA 59A(2001), "Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)," Gas (NFPA 59A 2001), IBR approved for §§ 193.2019(a), 193.2051, 193.2057, 193.2059 introductory text and (c), 193.2101(a), 193.2301, 193.2303, 193.2401, 193.2521, 193.2639(a), and 193.2801.~~
 - ~~(2) NFPA 59A (2006), "Standard for the Production, Storage, and Handling of Liquefied Natural Gas," 2006 edition, approved August 18, 2005, (NFPA 59A 2006), IBR approved for §§ 193.2101(b) and 193.2321(b).~~

~~§ 193.2015 [Reserved]~~

~~§ 193.2017 Plans and Procedures~~

- ~~(a) Each operator shall maintain at each LNG plant the plans and procedures required for that plant by this part. The plans and procedures must be available upon request for review and inspection by the Administrator or any State Agency that has submitted a current certification or agreement with respect to the plant under the pipeline safety laws (49 U.S.C. 60101 et seq.). In addition, each change to the plans or procedures must be available at the LNG plant for review and inspection within 20 days after the change is made.~~
- ~~(b) The Administrator or the State Agency that has submitted a current certification under~~

~~section 5(a) of the Natural Gas Pipeline Safety Act with respect to the pipeline facility governed by an operator's plans and procedures may, after notice and opportunity for hearing as provided in 49 CFR 190.206 or the relevant State procedures, require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety.~~

~~(c) — Each operator must review and update the plans and procedures required by this part—~~

~~(1) — When a component is changed significantly or a new component is installed; and~~

~~(2) — At intervals not exceeding 27 months, but at least once every 2 calendar years.~~

~~§ 193.2019 Mobile and Temporary LNG Facilities~~

~~(a) — Mobile and temporary LNG facilities for peakshaving application, for service maintenance during gas pipeline systems repair/alteration, or for other short-term applications need not meet the requirements of this part if the facilities are in compliance with applicable sections of NFPA 59A-2001 (incorporated by reference, see § 193.2013).~~

~~(b) — The state agency having jurisdiction over pipeline safety in the State in which the portable LNG equipment is to be located must be provided with a location description for the installation at least 2 weeks in advance, including to the extent practical, the details of siting, leakage containment or control, firefighting equipment, and methods employed to restrict public access, except that in the case of emergency where such notice is not possible, as much advance notice as possible must be provided.~~

~~SUBPART B – SITING REQUIREMENTS~~

~~§ 193.2051 Scope~~

~~Each LNG facility designed, constructed, replaced, relocated or significantly altered after March 31, 2000 must be provided with siting requirements in accordance with the requirements of this part and of NFPA 59A-2001 (incorporated by reference, see § 193.2013). In the event of a conflict between this part and NFPA 59A-2001, this part prevails.~~

~~§ 193.2055 [Reserved]~~

~~§ 193.2057 Thermal Radiation Protection~~

~~Each LNG container and LNG transfer system must have a thermal exclusion zone in accordance with section 2.2.3.2 of NFPA 59A-2001 (incorporated by reference, see § 193.2013) with the following exceptions:~~

~~(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.~~

~~(b) — In calculating exclusion distances, the wind speed producing the maximum exclusion~~

~~distances shall be used except for wind speeds that occur less than 5 percent of the time based on recorded data for the area.~~

- ~~(c) In calculating exclusion distances, the ambient temperature and relative humidity that produce the maximum exclusion distances shall be used except for values that occur less than five percent of the time based on recorded data for the area.~~

~~§ 193.2059 Flammable Vapor-gas Dispersion Protection~~

~~Each LNG container and LNG transfer system must have a dispersion exclusion zone in accordance with sections 2.2.3.3 and 2.2.3.4 of NFPA-59A-2001 (incorporated by reference, see § 193.2013) with the following exceptions:~~

- ~~(a) Flammable vapor-gas dispersion distances must be determined in accordance with the model described in GTI-04/0049, "LNG Vapor Dispersion Prediction with the DEGADIS 2.1 Dense Gas Dispersion Model" (incorporated by reference, see § 193.2013). Alternatively, in order to account for additional cloud dilution which may be caused by the complex flow patterns induced by tank and dike structure, dispersion distances may be calculated in accordance with the model described in the Gas Research Institute report GRI-96/0396.5 (incorporated by reference, see § 193.2013), "Evaluation of Mitigation Methods for Accidental LNG Releases. Volume 5: Using FEM3A for LNG Accident Consequence Analyses." The use of alternate models which take into account the same physical factors and have been validated by experimental test data shall be permitted, subject to the Administrator's approval.~~
- ~~(b) The following dispersion parameters must be used in computing dispersion distances:~~
- ~~(1) Average gas concentration in air = 2.5 percent.~~
 - ~~(2) Dispersion conditions are a combination of those which result in longer predicted downwind dispersion distances than other weather conditions at the site at least 90 percent of the time, based on figures maintained by National Weather Service of the U.S. Department of Commerce, or as an alternative where the model used gives longer distances at lower wind speeds, Atmospheric Stability (Pasquill Class) F, wind speed = 4.5 miles per hour (2.01 meters/sec) at reference height of 10 meters, relative humidity = 50.0 percent, and atmospheric temperature = average in the region.~~
 - ~~(3) The elevation for contour (receptor) output H = 0.5 meters.~~
 - ~~(4) A surface roughness factor of 0.03 meters shall be used. Higher values for the roughness factor may be used if it can be shown that the terrain both upwind and downwind of the vapor cloud has dense vegetation and that the vapor cloud height is more than ten times the height of the obstacles encountered by the vapor cloud.~~
- ~~(c) The design spill shall be determined in accordance with section 2.2.3.5 of NFPA-59A-2001 (incorporated by reference, see § 193.2013).~~

~~§§ 193.2061-193.2065 [Reserved]~~

~~§ 193.2067 Wind Forces~~

- ~~(a) LNG facilities must be designed to withstand without loss of structural or functional integrity;~~

- (1) ~~The direct effect of wind forces;~~
- (2) ~~The pressure differential between the interior and exterior of a confining, or partially confining, structure; and~~
- (3) ~~In the case of impounding systems for LNG storage tanks, impact forces and potential penetrations by wind borne missiles.~~
- (b) ~~The wind forces at the location of the specific facility must be based on one of the following:~~
 - (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 (incorporated by reference, see § 193.2013).~~
 - (2) ~~For all other LNG facilities:~~
 - (i) ~~An assumed sustained wind velocity of not less than 150 miles per hour, unless the Administrator finds a lower velocity is justified by adequate supportive data; or~~
 - (ii) ~~The most critical combination of wind velocity and duration, with respect to the effect on the structure, having a probability of exceedance in a 50-year period of 0.5 percent or less, if adequate wind data are available and the probabilistic methodology is reliable.~~

~~§§ 193.2069-193.2073 [Reserved]~~

SUBPART C -- DESIGN

§ 193.2101 Scope

- (a) ~~Each LNG facility designed after March 31, 2000 must comply with the 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-2001, the requirements in this Part prevail.~~
- (b) ~~Each stationary LNG storage tank 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 Std 620 (incorporated by reference, see § 193.2013) for seismic design.~~

~~§§ 193.2103-193.2117 [Reserved]~~

Materials

§ 193.2119 Records

~~Each operator shall keep a record of all materials for components, buildings, foundations, and support systems, as necessary to verify that material properties meet the requirements of this part. These records must be maintained for the life of the item concerned.~~

Design of Components and Buildings

~~§§ 193.2121-193.2153 [Reserved]~~

Impoundment Design and Capacity

~~§ 193.2155 Structural Requirements~~

- ~~(a) — The structural members of an impoundment system must be designed and constructed to prevent impairment of the system's performance reliability and structural integrity as a result of the following:~~
- ~~(1) — The imposed loading from—~~
 - ~~(i) — Full hydrostatic head of impounded LNG;~~
 - ~~(ii) — Hydrodynamic action, including the effect of any material injected into the system for spill control;~~
 - ~~(iii) — The impingement of the trajectory of an LNG jet discharged at any predictable angle; and,~~
 - ~~(iv) — Anticipated hydraulic forces from a credible opening in the component or item served, assuming that the discharge pressure equals design pressure.~~
 - ~~(2) — The erosive action from a spill, including jetting of spilling LNG, and any other anticipated erosive action including surface water runoff, ice formation, dislodgment of ice formation, and snow removal.~~
 - ~~(3) — The effect of the temperature, any thermal gradient, and any other anticipated degradation resulting from sudden or localized contact with LNG.~~
 - ~~(4) — Exposure to fire from impounded LNG or from sources other than impounded LNG.~~
 - ~~(5) — If applicable, the potential impact and loading on the dike due to~~
 - ~~(i) — Collapse of the component or item served or adjacent components; and~~
 - ~~(ii) — If the LNG facility adjoins the right-of-way of any highway or railroad, collision by or explosion of a train, tank car, or tank truck that could reasonably be expected to cause the most severe loading.~~
- ~~(b) — An LNG storage tank must not be located within a horizontal distance of one mile (1.6 km) from the ends, or ¼ mile (0.4 km) from the nearest point of a runway, whichever is longer. The height of LNG structures in the vicinity of an airport must also comply with Federal Aviation Administration requirements in 14 CFR Section 1.1.~~

~~§§ 193.2157-193.2159 [Reserved]~~

~~§ 193.2161 Dikes, General~~

~~An outer wall of a component served by an impounding system may not be used as a dike unless the outer wall is constructed of concrete.~~

~~§§ 193.2163-193.2165 [Reserved]~~

~~§ 193.2167 Covered Systems~~

~~A covered impounding system is prohibited except for concrete wall designed tanks where the concrete wall is an outer wall serving as a dike.~~

~~§§ 193.2169-193.2171 [Reserved]~~

~~§ 193.2173 Water Removal~~

- ~~(a) — Impoundment areas must be constructed such that all areas drain completely to prevent water collection. Drainage pumps and piping must be provided to remove water from collecting in the impoundment area. Alternative means of draining may be acceptable subject to the Administrator's approval.~~
- ~~(b) — The water removal system must have adequate capacity to remove water at a rate equal to 25% of the maximum predictable collection rate from a storm of 10-year frequency and 1-hour duration, and other natural causes. For rainfall amounts, operators must use the "Rainfall Frequency Atlas of the United States" published by the National Weather Service of the U.S. Department of Commerce.~~
- ~~(c) — Sump pumps for water removal must—
 - ~~(1) — Be operated as necessary to keep the impounding space as dry as practical; and~~
 - ~~(2) — If sump pumps are designed for automatic operation, have redundant automatic shutdown controls to prevent operation when LNG is present.~~~~

~~§§ 193.2175-193.2179 [Reserved]~~

~~§ 193.2181 Impoundment Capacity: LNG Storage Tanks~~

~~Each impounding system serving an LNG storage tank must have a minimum volumetric liquid impoundment capacity of:~~

- ~~(a) — 110 percent of the LNG tank's maximum liquid capacity for an impoundment serving a single tank;~~
- ~~(b) — 100 percent of all tanks or 110 percent of the largest tank's maximum liquid capacity, whichever is greater, for the impoundment serving more than one tank; or~~
- ~~(c) — If the dike is designed to account for a surge in the event of catastrophic failure, then the impoundment capacity may be reduced to 100 percent in lieu of 110 percent.~~

~~§§ 193.2183-193.2185 [Reserved]~~

LNG Storage Tanks

~~§ 193.2187 Nonmetallic Membrane Liner~~

~~A flammable nonmetallic membrane liner may not be used as an inner container in a storage tank.~~

~~§§ 193.2189-193.2233 [Reserved]~~

SUBPART D — CONSTRUCTION

~~§ 193.2301 Scope~~

~~Each LNG facility constructed after March 31, 2000 must comply with requirements of this part and of NFPA 59A 2001 (incorporated by reference, see § 193.2013). In the event of a conflict between this part and NFPA 59A 2001, this part prevails.~~

~~§ 193.2303 Construction Acceptance~~

~~No person may place in service any component until it passes all applicable inspections and tests prescribed by this subpart and NFPA-59A-2001 (incorporated by reference, see § 193.2013).~~

~~§ 193.2304 Corrosion Control Overview~~

- ~~(a) Subject to paragraph (b) of this section, components may not be constructed, repaired, replaced, or significantly altered until a person qualified under § 193.2707(c) reviews the applicable design drawings and materials specifications from a corrosion control viewpoint and determines that the materials involved will not impair the safety or reliability of the component or any associated components.~~
- ~~(b) The repair, replacement, or significant alteration of components must be reviewed only if the action to be taken—
 - ~~(1) Involves a change in the original materials specified;~~
 - ~~(2) Is due to a failure caused by corrosion; or~~
 - ~~(3) Is occasioned by inspection revealing a significant deterioration of the component due to corrosion.~~~~

~~§§ 193.2305-193.2319 [Reserved]~~

~~§ 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 (BPVC) (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 BPVC (Section VIII Division 1).~~
- ~~(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 Std-59A-2006 (incorporated by reference, see § 193.2013);~~
 - ~~(2) Appendices Q and C of API Std 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.~~

~~§§ 193.2323-193.2329 [Reserved]~~

SUBPART E – EQUIPMENT

~~§ 193.2401 Scope~~

~~After March 31, 2000, each new, replaced, relocated or significantly altered vaporization equipment, liquefaction equipment, and control systems must be designed, fabricated, and installed in accordance with requirements of this part and of NFPA 59A-2001 (incorporated by reference, see § 193.2013). In the event of a conflict between this part and NFPA 59A-2001, this part prevails.~~

VAPORIZATION EQUIPMENT

~~§§ 193.2403-193.2439 [Reserved]~~

~~§ 193.2441 Control Center~~

~~Each LNG plant must have a control center from which operations and warning devices are monitored as required by this part. A control center must have the following capabilities and characteristics:~~

- ~~(a) — It must be located apart or protected from other LNG facilities so that it is operational during a controllable emergency.~~
- ~~(b) — Each remotely actuated control system and each automatic shutdown control system required by this part must be operable from the control center.~~
- ~~(c) — Each control center must have personnel in continuous attendance while any of the components under its control are in operation, unless the control is being performed from another control center which has personnel in continuous attendance.~~
- ~~(d) — If more than one control center is located at an LNG plant, each control center must have more than one means of communication with each other center.~~
- ~~(e) — Each control center must have a means of communicating a warning of hazardous conditions to other locations within the plant frequented by personnel.~~

~~§ 193.2443 [Reserved]~~

~~§ 193.2445 Sources of Power~~

- ~~(a) — Electrical control systems, means of communication, emergency lighting, and firefighting systems must have at least two sources of power which function so that failure of one source does not affect the capability of the other source.~~
- ~~(b) — Where auxiliary generators are used as a second source of electrical power
 - ~~(1) — They must be located apart or protected from components so that they are not unusable during a controllable emergency; and~~
 - ~~(2) — Fuel supply must be protected from hazards.~~~~

SUBPART F – OPERATIONS

~~§ 193.2501 Scope~~

~~This subpart prescribes requirements for the operation of LNG facilities~~

~~§ 193.2503 Operating Procedures~~

~~Each operator shall follow one or more manuals of written procedures to provide safety in normal operation and in responding to an abnormal operation that would affect safety. The procedures must include provisions for:~~

- ~~(a) — Monitoring components or buildings according to the requirements of § 193.2507.~~
- ~~(b) — Startup and shutdown, including for initial startup, performance testing to demonstrate that components will operate satisfactory in service.~~
- ~~(c) — Recognizing abnormal operating conditions.~~
- ~~(d) — Purging and inserting components according to the requirements of § 193.2517.~~
- ~~(e) — In the case of vaporization, maintaining the vaporization rate, temperature and pressure so that the resultant gas is within limits established for the vaporizer and the downstream piping.~~
- ~~(f) — In the case of liquefaction, maintaining temperatures, pressures, pressure differentials and flow rates, as applicable, within their design limits for:
 - ~~(1) — Boilers;~~
 - ~~(2) — Turbines and other prime movers;~~
 - ~~(3) — Pumps, compressors, and expanders;~~
 - ~~(4) — Purification and regeneration equipment; and~~
 - ~~(5) — Equipment within cold boxes.~~~~
- ~~(g) — Cooldown of components according to the requirements of § 193.2505.~~

~~§ 193.2505 Cooldown~~

- ~~(a) — The cooldown of each system of components that is subjected to cryogenic temperatures must be limited to a rate and distribution pattern that keeps thermal stresses within design limits during the cooldown period, paying particular attention to the performance of expansion and contraction devices.~~
- ~~(b) — After cooldown stabilization is reached, cryogenic piping systems must be checked for leaks in areas of flanges, valves, and seals.~~

~~§ 193.2507 Monitoring Operations~~

~~Each component in operation or building in which a hazard to persons or property could exist must be monitored to detect fire or any malfunction or flammable fluid that could cause a hazardous condition. Monitoring must be accomplished by watching or listening from an attended control center for warning alarms, such as gas, temperature, pressure, vacuum, and flow alarms, or by conducting an inspection or test at intervals specified in the operating procedures.~~

~~§ 193.2509 Emergency Procedures~~

- ~~(a) — Each operator shall determine the types and places of emergencies other than fires that may reasonably be expected to occur at an LNG plant due to operating malfunctions, structural collapse, personnel error, forces of nature, and activities adjacent to the plant.~~

- ~~(b) To adequately handle each type of emergency identified under paragraph (a) of this section and each fire emergency, each operator shall follow one or more manuals of written procedures. The procedures must provide for the following:~~
- ~~(1) Responding to controllable emergencies, including notifying personnel and using equipment appropriate for handling the emergency.~~
 - ~~(2) Recognizing an uncontrollable emergency and taking action to minimize harm to the public and personnel, including prompt notification of appropriate local officials of the emergency and possible need for evacuation of the public in the vicinity of the LNG plant.~~
 - ~~(3) Coordinating with appropriate local officials in preparation of an emergency evacuation plan, which sets forth the steps required to protect the public in the event of an emergency, including catastrophic failure of an LNG storage tank.~~
 - ~~(4) Cooperating with appropriate local officials in evacuations and emergencies requiring mutual assistance and keeping these officials advised of:
 - ~~(i) The LNG plant fire control equipment, its location, and quantity of units located throughout the plant;~~
 - ~~(ii) Potential hazards at the plant, including fires;~~
 - ~~(iii) Communication and emergency control capabilities at the LNG plant; and,~~
 - ~~(iv) The status of each emergency.~~~~

~~§ 193.2511 Personnel Safety~~

- ~~(a) Each operator shall provide any special protective clothing and equipment necessary for the safety of personnel while they are performing emergency response duties.~~
- ~~(b) All personnel who are normally on duty at a fixed location, such as a building or yard, where they could be harmed by thermal radiation from a burning pool of impounded liquid, must be provided a means of protection at that location from the harmful effects of thermal radiation or a means of escape.~~
- ~~(c) Each LNG plant must be equipped with suitable first-aid material, the location of which is clearly marked and readily available to personnel.~~

~~§ 193.2513 Transfer Procedures~~

- ~~(a) Each transfer of LNG or other hazardous fluid must be conducted in accordance with one or more manuals of written procedures to provide for safe transfers.~~
- ~~(b) The transfer procedures must include provisions for personnel to:
 - ~~(1) Before transfer, verify that the transfer system is ready for use, with connections and controls in proper positions, including if the system could contain a combustible mixture, verifying that it has been adequately purged in accordance with a procedure which meets the requirements of Purging Principles and Practices (incorporated by reference, see § 193.2013);~~
 - ~~(2) Before transfer, verify that each receiving container or tank vehicle does not contain any substance that would be incompatible with the incoming fluid and that there is sufficient capacity available to receive the amount of fluid to be transferred;~~~~

- ~~(3) — Before transfer, verify the maximum filling volume of each receiving container or tank vehicle to ensure that expansion of the incoming fluid due to warming will not result in overfilling or overpressure;~~
- ~~(4) — When making bulk transfer of LNG into a partially filled (excluding cooldown heel) container, determine any differences in temperature or specific gravity between the LNG being transferred and the LNG already in the container and, if necessary, provide a means to prevent rollover due to stratification;~~
- ~~(5) — Verify that the transfer operations are proceeding within design conditions and that overpressure or overfilling does not occur by monitoring applicable flow rates, liquid levels, and vapor returns;~~
- ~~(6) — Manually terminate the flow before overfilling or overpressure occurs; and,~~
- ~~(7) — Deactivate cargo transfer systems in a safe manner by depressurizing, venting, and disconnecting lines and conducting any other appropriate operations.~~
- ~~(c) — In addition to the requirements of paragraph (b) of this section, the procedures for cargo transfer must be located at the transfer area and include provisions for personnel to:~~
 - ~~(1) — Be in constant attendance during all cargo transfer operations;~~
 - ~~(2) — Prohibit the backing of tank trucks in the transfer area, except when a person is positioned at the rear of the truck giving instructions to the driver;~~
 - ~~(3) — Before transfer, verify that:
 - ~~(i) — Each tank car or tank truck complies with applicable regulations governing its use;~~
 - ~~(ii) — All transfer hoses have been visually inspected for damage and defects;~~
 - ~~(iii) — Each tank truck is properly immobilized with chock wheels, and electrically grounded; and,~~
 - ~~(iv) — Each tank truck engine is shut off unless it is required for transfer operations;~~~~
 - ~~(4) — Prevent a tank truck engine that is off during transfer operations from being restarted until the transfer lines have been disconnected and any released vapors have dissipated;~~
 - ~~(5) — Prevent loading LNG into a tank car or tank truck that is not in exclusive LNG service or that does not contain a positive pressure if it is in exclusive LNG service, until after the oxygen content in the tank is tested and if it exceeds 2 percent by volume, purged in accordance with a procedure that meets the requirements of Purging Principles and Practices (incorporated by reference, see § 193.2013);~~
 - ~~(6) — Verify that all transfer lines have been disconnected and equipment cleared before the tank car or tank truck is moved from the transfer position; and~~
 - ~~(7) — Verify that transfers into a pipeline system will not exceed the pressure or temperature limits of the system.~~

§ 193.2515 Investigations of Failures

- ~~(a) — Each operator shall investigate the cause of each explosion, fire, or LNG spill or leak which results in:
 - ~~(1) — Death or injury requiring hospitalization; or~~~~

- ~~(2) Property damage exceeding \$10,000.~~
- ~~(b) As a result of the investigation, appropriate action must be taken to minimize recurrence of the incident.~~
- ~~(c) If the Administrator or relevant state agency under the pipeline safety laws (49 U.S.C. 60101 *et seq.*) investigates an incident, the operator involved shall make available all relevant information and provide reasonable assistance in conducting the investigation. Unless necessary to restore or maintain service, or for safety, no component involved in the incident may be moved from its location or otherwise altered until the investigation is complete or the investigating agency otherwise provides. Where components must be moved for operational or safety reasons, they must not be removed from the plant site and must be maintained intact to the extent practicable until the investigation is complete or the investigating agency otherwise provides.~~

~~§ 193.2517 Purging~~

~~When necessary for safety, components that could accumulate significant amounts of combustible mixtures must be purged in accordance with a procedure which meets the provisions of the "Purging Principles and Practices (incorporated by reference, see § 193.2013)" after being taken out of service and before being returned to service.~~

~~§ 193.2519 Communication Systems~~

- ~~(a) Each LNG plant must have a primary communication system that provides for verbal communications between all operating personnel at their work stations in the LNG plant.~~
- ~~(b) Each LNG plant in excess of 70,000 gallons (265,000 liters) storage capacity must have an emergency communication system that provides for verbal communications between all persons and locations necessary for the orderly shutdown of operating equipment and the operation of safety equipment in time of emergency. The emergency communication system must be independent of and physically separated from the primary communication system and the security communication system under § 193.2909.~~
- ~~(c) Each communication system required by this part must have an auxiliary source of power, except sound-powered equipment.~~

~~§ 193.2521 Operating Records~~

~~Each operator shall maintain a record of results of each inspection, test and investigation required by this subpart. For each LNG facility that is designed and constructed after March 31, 2000 the operator shall also maintain related inspection, testing, and investigation records that NFPA-59A-2001 (incorporated by reference, see § 193.2013) requires. Such records, whether required by this part or NFPA-59A-2001, must be kept for a period of not less than five years.~~

SUBPART G - MAINTENANCE

~~§ 193.2601 Scope~~

~~This subpart prescribes requirements for maintaining components at LNG plants.~~

~~§ 193.2603 General~~

- ~~(a) Each component in service, including its support system, must be maintained in a condition~~

~~that is compatible with its operational or safety purpose by repair, replacement, or other means.~~

- ~~(b) An operator may not place, return, or continue in service any component which is not maintained in accordance with this subpart.~~
- ~~(c) Each component taken out of service must be identified in the records kept under § 193.2639.~~
- ~~(d) If a safety device is taken out of service for maintenance, the component being served by the device must be taken out of service unless the same safety function is provided by an alternate means.~~
- ~~(e) If the inadvertent operation of a component taken out of service could cause a hazardous condition, that component must have a tag attached to the controls bearing the words "do not operate" or words of comparable meaning.~~

~~§ 193.2605 Maintenance Procedures~~

- ~~(a) Each operator shall determine and perform, consistent with generally accepted engineering practice, the periodic inspections or tests needed to meet the applicable requirements of this subpart and to verify that components meet the maintenance standards prescribed by this subpart.~~
- ~~(b) Each operator shall follow one or more manuals of written procedures for the maintenance of each component, including any required corrosion control. The procedure must include:
 - ~~(1) The details of the inspections or tests determined under paragraph (a) of this section and their frequency of performance; and~~
 - ~~(2) A description of other actions necessary to maintain the LNG plant in accordance with the requirements of this subpart.~~~~
- ~~(c) Each operator shall include in the manual required by paragraph (b) of this section instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of § 191.23 of this subchapter.~~

~~§ 193.2607 Foreign Material~~

- ~~(a) The presence of foreign material, contaminants, or ice shall be avoided or controlled to maintain the operational safety of each component.~~
- ~~(b) LNG plant grounds must be free from rubbish, debris, and other material which present a fire hazard. Grass areas on the LNG plant grounds must be maintained in a manner that does not present a fire hazard.~~

~~§ 193.2609 Support Systems~~

~~Each support system or foundation of each component must be inspected for any detrimental change that could impair support.~~

~~§ 193.2611 Fire Protection~~

- ~~(a) Maintenance activities on fire control equipment must be scheduled so that a minimum of equipment is taken out of service at any one time and is returned to service in a reasonable period of time.~~

- ~~(b) Access routes for movement of fire control equipment within each LNG plant must be maintained to reasonably provide for use in all weather conditions.~~

§ 193.2613 Auxiliary Power Sources

~~Each auxiliary power source must be tested monthly to check its operational capability and tested annually for capacity. The capacity test must take into account the power needed to start up and simultaneously operate equipment that would have to be served by that power source in an emergency.~~

§ 193.2615 Isolating and Purging

- ~~(a) Before personnel begin maintenance activities on components handling flammable fluids which are isolated for maintenance, the component must be purged in accordance with a procedure which meets the requirements of Purging Principles and Practices (incorporated by reference, see § 193.2013) unless the maintenance procedures under § 193.2605 provide that the activity can be safely performed without purging.~~
- ~~(b) If the component or maintenance activity provides an ignition source, a technique in addition to isolation valves (such as removing spool pieces or valves and blank flanging the piping, or double block and bleed valving) must be used to ensure that the work area is free of flammable fluids.~~

§ 193.2617 Repairs

- ~~(a) Repair work on components must be performed and tested in a manner which:
 - ~~(1) As far as practicable, complies with the applicable requirements of Subpart D of this part; and~~
 - ~~(2) Assures the integrity and operational safety of the component being repaired.~~~~
- ~~(b) For repairs made while a component is operating, each operator shall include in the maintenance procedures under § 193.2605 appropriate precautions to maintain the safety of personnel and property during repair activities.~~

§ 193.2619 Control Systems

- ~~(a) Each control system must be properly adjusted to operate within design limits.~~
- ~~(b) If a control system is out of service for 30 days or more, it must be inspected and tested for operational capability before returning it to service.~~
- ~~(c) Control systems in service, but not normally in operation, such as relief valves and automatic shutdown devices, and control systems for internal shutoff valves for bottom penetration tanks must be inspected and tested once each calendar year, not exceeding 15 months, with the following exceptions:
 - ~~(1) Control systems used seasonally, such as for liquefaction or vaporization, must be inspected and tested before use each season.~~
 - ~~(2) Control systems that are intended for fire protection must be inspected and tested at regular intervals not to exceed 6 months.~~~~
- ~~(d) Control systems that are normally in operation, such as required by a base load system, must be inspected and tested once each calendar year but with intervals not exceeding 15 months.~~
- ~~(e) Relief valves must be inspected and tested for verification of the valve seat lifting pressure and reseating.~~

~~§ 193.2621 Testing Transfer Hoses~~

~~Hoses used in LNG or flammable refrigerant transfer systems must be:~~

- ~~(a) Tested once each calendar year, but with intervals not exceeding 15 months, to the maximum pump pressure or relief valve setting; and~~
- ~~(b) Visually inspected for damage or defects before each use.~~

~~§ 193.2623 Inspecting LNG Storage Tanks~~

~~Each LNG storage tank must be inspected or tested to verify that each of the following conditions does not impair the structural integrity or safety of the tank:~~

- ~~(a) Foundation and tank movement during normal operation and after a major meteorological or geophysical disturbance.~~
- ~~(b) Inner tank leakage.~~
- ~~(c) Effectiveness of insulation.~~
- ~~(d) Frost heave.~~

~~§ 193.2625 Corrosion Protection~~

- ~~(a) Each operator shall determine which metallic components could, unless corrosion is controlled, have their integrity or reliability adversely affected by external, internal, or atmospheric corrosion during their intended service life.~~
- ~~(b) Components whose integrity or reliability could be adversely affected by corrosion must be either—~~
 - ~~(1) Protected from corrosion in accordance with §§ 193.2627 through 193.2635, as applicable; or~~
 - ~~(2) Inspected and replaced under a program of scheduled maintenance in accordance with procedures established under § 193.2605.~~

~~§ 193.2627 Atmospheric Corrosion Control~~

~~Each exposed component that is subject to atmospheric corrosive attack must be protected from atmospheric corrosion by:~~

- ~~(a) Material that has been designed and selected to resist the corrosive atmosphere involved; or~~
- ~~(b) Suitable coating or jacketing.~~

~~§ 193.2629 External Corrosion Control; Buried or Submerged Components~~

- ~~(a) Each buried or submerged component that is subject to external corrosive attack must be protected from external corrosion by:~~
 - ~~(1) Material that has been designed and selected to resist the corrosive environment involved; or~~
 - ~~(2) The following means:~~

- ~~(i) — An external protective coating designed and installed to prevent corrosion attack and to meet the requirements of § 192.461 of this chapter; and~~
 - ~~(ii) — A cathodic protection system designed to protect components in their entirety in accordance with the requirements of § 192.463 of this chapter and placed in operation before October 23, 1981, or within 1 year after the component is constructed or installed, whichever is later.~~
- ~~(b) — Where cathodic protection is applied, components that are electrically interconnected must be protected as a unit.~~

~~§ 193.2631 Internal Corrosion Control~~

~~Each component that is subject to internal corrosive attack must be protected from internal corrosion by:~~

- ~~(a) — Material that has been designed and selected to resist the corrosive fluid involved; or~~
- ~~(b) — Suitable coating, inhibitor, or other means.~~

~~§ 193.2633 Interference Currents~~

- ~~(a) — Each component that is subject to electrical current interference must be protected by a continuing program to minimize the detrimental effects of currents.~~
- ~~(b) — Each cathodic protection system must be designed and installed so as to minimize any adverse effects it might cause to adjacent metal components.~~
- ~~(c) — Each impressed current power source must be installed and maintained to prevent adverse interference with communications and control systems.~~

~~§ 193.2635 Monitoring Corrosion Control~~

~~Corrosion protection provided as required by this subpart must be periodically monitored to give early recognition of ineffective corrosion protection, including the following, as applicable:~~

- ~~(a) — Each buried or submerged component under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of § 192.463 of this chapter.~~
- ~~(b) — Each cathodic protection rectifier or other impressed current power source must be inspected at least six times each calendar year, but with intervals not exceeding 2½ months, to ensure that it is operating properly.~~
- ~~(c) — Each reverse current switch, each diode, and each interference bond whose failure would jeopardize component protection must be electrically checked for proper performance at least six times each calendar year, but with intervals not exceeding 2½ months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.~~
- ~~(d) — Each component that is protected from atmospheric corrosion must be inspected at intervals not exceeding 3 years.~~
- ~~(e) — If a component is protected from internal corrosion, monitoring devices designed to detect internal corrosion, such as coupons or probes, must be located where corrosion is most likely to occur. However, monitoring is not required for corrosion resistant materials if the~~

~~operator can demonstrate that the component will not be adversely affected by internal corrosion during its service life. Internal corrosion control monitoring devices must be checked at least two times each calendar year, but with intervals not exceeding 7½ months.~~

~~§ 193.2637 Remedial Measures~~

~~Prompt corrective or remedial action must be taken whenever an operator learns by inspection or otherwise that atmospheric, external, or internal corrosion is not controlled as required by this subpart.~~

~~§ 193.2639 Maintenance Records~~

- ~~(a) — Each operator shall keep a record at each LNG plant of the date and type of each maintenance activity performed on each component to meet the requirements of this part. For each LNG facility that is designed and constructed after March 31, 2000 the operator shall also maintain related periodic inspection and testing records that NFPA-59A-2001 (incorporated by reference, see § 193.2013) requires. Maintenance records, whether required by this part or NFPA-59A-2001, must be kept for a period of not less than five years.~~
- ~~(b) — Each operator shall maintain records or maps to show the location of cathodically protected components, neighboring structures bonded to the cathodic protection system, and corrosion protection equipment.~~
- ~~(c) — Each of the following records must be retained for as long as the LNG facility remains in service:
 - ~~(1) — Each record or map required by paragraph (b) of this section.~~
 - ~~(2) — Records of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures.~~~~

SUBPART H- PERSONNEL QUALIFICATIONS AND TRAINING

~~§ 193.2701 Scope~~

~~This subpart prescribes requirements for personnel qualifications and training.~~

~~§ 193.2703 Design and Fabrication~~

~~For the design and fabrication of components, each operator shall use _~~

- ~~(a) — With respect to design, persons who have demonstrated competence by training or experience in the design of comparable components.~~
- ~~(b) — With respect to fabrication, persons who have demonstrated competence by training or experience in the fabrication of comparable components.~~

~~§ 193.2705 Construction, Installation, Inspection, and Testing~~

- ~~(a) — Supervisors and other personnel utilized for construction, installation, inspection, or testing must have demonstrated their capability to perform satisfactorily the assigned function by appropriate training in the methods and equipment to be used or related experience and accomplishments.~~

- (b) ~~Each operator must periodically determine whether inspectors performing construction, installation, and testing duties required by this part are satisfactorily performing their assigned function.~~

~~§ 193.2707 Operations and Maintenance~~

- (a) ~~Each operator shall utilize for operation or maintenance of components only those personnel who have demonstrated their capability to perform their assigned functions by—~~
 - (1) ~~Successful completion of the training required by §§ 193.2713 and 193.2717;~~
 - (2) ~~Experience related to the assigned operation or maintenance function; and,~~
 - (3) ~~Acceptable performance on a proficiency test relevant to the assigned function.~~
- (b) ~~A person who does not meet the requirements of paragraph (a) of this section may operate or maintain a component when accompanied and directed by an individual who meets the requirements.~~
- (c) ~~Corrosion control procedures under § 193.2605(b), including those for the design, installation, operation, and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified by experience and training in corrosion control technology.~~

~~§ 193.2709 Security~~

~~Personnel having security duties must be qualified to perform their assigned duties by successful completion of the training required under § 193.2715.~~

~~§ 193.2711 Personnel Health~~

~~Each operator shall follow a written plan to verify that personnel assigned operating, maintenance, security, or fire protection duties at the LNG plant do not have any physical condition that would impair performance of their assigned duties. The plan must be designed to detect both readily observable disorders, such as physical handicaps or injury, and conditions requiring professional examination for discovery.~~

~~§ 193.2713 Training: Operations and Maintenance~~

- (a) ~~Each operator shall provide and implement a written plan of initial training to instruct—~~
 - (1) ~~All permanent maintenance, operating, and supervisory personnel—~~
 - (i) ~~About the characteristics and hazards of LNG and other flammable fluids used or handled at the facility, including, with regard to LNG, low temperatures, flammability of mixtures with air, odorless vapor, boiloff characteristics, and reaction to water and water spray;~~
 - (ii) ~~About the potential hazards involved in operating and maintenance activities; and,~~
 - (iii) ~~To carry out aspects of the operating and maintenance procedures under §§ 193.2503 and 193.2605 that relate to their assigned functions; and~~
 - (2) ~~All personnel—~~
 - (i) ~~To carry out the emergency procedures under § 193.2509 that relate to their assigned functions; and~~
 - (ii) ~~To give first-aid; and,~~

- ~~(3) All operating and appropriate supervisory personnel—
 - ~~(i) To understand detailed instructions on the facility operations, including controls, functions, and operating procedures; and~~
 - ~~(ii) To understand the LNG transfer procedures provided under § 193.2513.~~~~
- ~~(b) A written plan of continuing instruction must be conducted at intervals of not more than 2 years to keep all personnel current on the knowledge and skills they gained in the program of initial instruction.~~

~~§ 193.2715 Training: Security~~

- ~~(a) Personnel responsible for security at an LNG plant must be trained in accordance with a written plan of initial instruction to:
 - ~~(1) Recognize breaches of security;~~
 - ~~(2) Carry out the security procedures under § 193.2903 that relate to their assigned duties;~~
 - ~~(3) Be familiar with basic plant operations and emergency procedures, as necessary to effectively perform their assigned duties; and,~~
 - ~~(4) Recognize conditions where security assistance is needed.~~~~
- ~~(b) A written plan of continuing instruction must be conducted at intervals of not more than 2 years to keep all personnel having security duties current on the knowledge and skills they gained in the program of initial instruction.~~

~~§ 193.2717 Training: Fire Protection~~

- ~~(a) All personnel involved in maintenance and operations of an LNG plant, including their immediate supervisors, must be trained according to a written plan of initial instruction, including plant fire drills, to:
 - ~~(1) Know the potential causes and areas of fire;~~
 - ~~(2) Know the types, sizes, and predictable consequences of fire; and~~
 - ~~(3) Know and be able to perform their assigned fire control duties according to the procedures established under § 193.2509 and by proper use of equipment provided under § 193.2801.~~~~
- ~~(b) A written plan of continuing instruction, including plant fire drills, must be conducted at intervals of not more than 2 years to keep personnel current on the knowledge and skills they gained in the instruction under paragraph (a) of this section.~~
- ~~(c) Plant fire drills must provide personnel hands-on experience in carrying out their duties under the fire emergency procedures required by § 193.2509.~~

~~§ 193.2719 Training: Records~~

- ~~(a) Each operator shall maintain a system of records which
 - ~~(1) Provide evidence that the training programs required by this subpart have been implemented; and~~
 - ~~(2) Provide evidence that personnel have undergone and satisfactorily completed the~~~~

~~required training programs.~~

- ~~(b) Records must be maintained for 1 year after personnel are no longer assigned duties at the LNG plant.~~

SUBPART I - FIRE PROTECTION

§ 193.2801 Fire Protection

~~Each operator must provide and maintain fire protection at LNG plants according to sections 9.1 through 9.7 and section 9.9 of NFPA 59A 2001 (incorporated by reference, see § 193.2013). However, LNG plants existing on March 31, 2000, need not comply with provisions on emergency shutdown systems, water delivery systems, detection systems, and personnel qualification and training until September 12, 2005.~~

§ 193.2803-193.2821 [Reserved]

SUBPART J - SECURITY

§ 193.2901 Scope

~~This subpart prescribes requirements for security at LNG plants. However, the requirements do not apply to existing LNG plants that do not contain LNG.~~

§ 193.2903 Security Procedures

~~Each operator shall prepare and follow one or more manuals of written procedures to provide security for each LNG plant. The procedures must be available at the plant in accordance with § 193.2017 and include at least:~~

- ~~(a) A description and schedule of security inspections and patrols performed in accordance with § 193.2913;~~
- ~~(b) A list of security personnel positions or responsibilities utilized at the LNG plant;~~
- ~~(c) A brief description of the duties associated with each security personnel position or responsibility;~~
- ~~(d) Instructions for actions to be taken, including notification of other appropriate plant personnel and law enforcement officials, when there is any indication of an actual or attempted breach of security;~~
- ~~(e) Methods for determining which persons are allowed access to the LNG plant;~~
- ~~(f) Positive identification of all persons entering the plant and on the plant, including methods at least as effective as picture badges; and~~
- ~~(g) Liaison with local law enforcement officials to keep them informed about current security procedures under this section.~~

§ 193.2905 Protective Enclosures

- ~~(a) The following facilities must be surrounded by a protective enclosure:
 - ~~(1) Storage tanks;~~~~

- ~~(2) — Impounding systems;~~
- ~~(3) — Vapor barriers;~~
- ~~(4) — Cargo transfer systems;~~
- ~~(5) — Process, liquefaction, and vaporization equipment;~~
- ~~(6) — Control rooms and stations;~~
- ~~(7) — Control systems;~~
- ~~(8) — Fire control equipment;~~
- ~~(9) — Security communications systems; and,~~
- ~~(10) — Alternative power sources.~~

~~The protective enclosure may be one or more separate enclosures surrounding a single facility or multiple facilities.~~

- ~~(b) — Ground elevations outside a protective enclosure must be graded in a manner that does not impair the effectiveness of the enclosure.~~
- ~~(c) — Protective enclosures may not be located near features outside of the facility, such as trees, poles, or buildings, which could be used to breach the security.~~
- ~~(d) — At least two accesses must be provided in each protective enclosure and be located to minimize the escape distance in the event of emergency.~~
- ~~(e) — Each access must be locked unless it is continuously guarded. During normal operations, an access may be unlocked only by persons designated in writing by the operator. During an emergency, a means must be readily available to all facility personnel within the protective enclosure to open each access.~~

~~§ 193.2907 Protective Enclosure Construction~~

- ~~(a) — Each protective enclosure must have sufficient strength and configuration to obstruct unauthorized access to the facilities enclosed.~~
- ~~(b) — Openings in or under protective enclosures must be secured by grates, doors or covers of construction and fastening of sufficient strength such that the integrity of the protective enclosure is not reduced by any opening.~~

~~§ 193.2909 Security Communications~~

~~A means must be provided for:~~

- ~~(a) — Prompt communications between personnel having supervisory security duties and law enforcement officials; and~~
- ~~(b) — Direct communications between all on-duty personnel having security duties and all control rooms and control stations.~~

~~§ 193.2911 Security Lighting~~

~~Where security warning systems are not provided for security monitoring under § 193.2913, the area around the facilities listed under § 193.2905(a) and each protective enclosure must be illuminated with a minimum in-service lighting intensity of not less than 2.2 lux (0.2 ftc) between sunset and sunrise.~~

~~§ 193.2913 Security Monitoring~~

~~Each protective enclosure and the area around each facility listed in § 193.2905(a) must be monitored for the presence of unauthorized persons. Monitoring must be by visual observation in accordance with the schedule in the security procedures under § 193.2903(a) or by security warning systems that continuously transmit data to an attended location. At an LNG plant with less than 40,000 m³ (250,000 bbl) of storage capacity, only the protective enclosure must be monitored.~~

~~§ 193.2915 Alternative Power Sources~~

~~An alternative source of power that meets the requirements of § 193.2445 must be provided for security lighting and security monitoring and warning systems required under §§ 193.2911 and 193.2913.~~

~~§ 193.2917 Warning Signs~~

- ~~(a) — Warning signs must be conspicuously placed along each protective enclosure at intervals so that at least one sign is recognizable at night from a distance of 30 m (100 ft.) from any way that could reasonably be used to approach the enclosure.~~
- ~~(b) — Signs must be marked with at least the following on a background of sharply contrasting color: The words "NO TRESPASSING", or words of comparable meaning.~~

PART 199 - DRUG AND ALCOHOL TESTING

SUBPART A - GENERAL

§ 199.1 Scope

- (a) This part requires operators of pipeline facilities subject to part 192, 193, or 195 of this chapter to test covered employees for the presence of prohibited drugs and alcohol.

§ 199.2 Applicability

- (a) This part applies to pipeline operators only with respect to employees located within the territory of the United States, including those employees located within the limits of the “Outer Continental Shelf” as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).
- (b) This part does not apply to any person for whom compliance with this part would violate the domestic laws or policies of another country.
- (c) This part does not apply to covered functions performed on
 - (1) Master meter systems, as defined in § 191.3 of this chapter; or
 - (2) Pipeline systems that transport only petroleum gas or petroleum gas/air mixtures.

§ 199.3 Definitions

As used in this part—

Accident means an incident reportable under Part 191 involving gas pipeline facilities or LNG facilities.

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

Covered employee, employee, or individual to be tested means a person who performs a covered function, including persons employed by operators, contractors engaged by operators, and persons employed by such contractors.

Covered function means an operations, maintenance, or emergency-response function regulated by part 192, 193, or 195 of this chapter that is performed on a pipeline ~~or on an LNG facility~~.

DOT Procedures means the Procedures for Transportation Workplace Drug and Alcohol Testing Programs published by the Office of the Secretary of Transportation in part 40 of this title.

Fail a drug test means that the confirmation test result shows positive evidence of the presence under DOT Procedures of a prohibited drug in an employee's system.

Operator means a person who owns or operates pipeline facilities subject to Part 192 or Part 193 of this Code.

Pass a drug test means that initial testing or confirmation testing under DOT Procedures does not show evidence of the presence of a prohibited drug in a person's system.

Performs a covered function includes actually performing, ready to perform, or immediately available to perform a covered function.

Positive rate for random drug testing means the number of verified positive results for random drug tests conducted under this part plus the number of refusals of random drug tests required by this part, divided by the total number of random drug tests results (i.e., positives, negatives, and refusals) under this part.

Prohibited drug means any of the substances specified in 49 CFR part 40.

Refuse to submit, refuse, or refuse to take means behavior consistent with DOT Procedures concerning refusal to take a drug test or refusal to take an alcohol test.

State agency means an agency of any of the several states, the District of Columbia, or Puerto Rico that participates under the pipeline safety laws (49 U.S.C. 60101 *et seq.*).

§ 199.5 DOT Procedures

The anti-drug and alcohol programs required by this part must be conducted according to the requirements of this part and DOT Procedures. Terms and concepts used in this part have the same meaning as in DOT Procedures. Violations of DOT Procedures with respect to anti-drug and alcohol programs required by this part are violations of this part.

§ 199.7 Stand-down Waivers

- (a) Each operator who seeks a waiver under § 40.21 of this title from the stand-down restriction must submit an application for waiver in duplicate to the Associate Administrator for Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, 1200 New Jersey Avenue, SE, Washington, DC 20590-0001.
- (b) Each application must -
 - (1) Identify §40.21 of this title as the rule from which the waiver is sought;
 - (2) Explain why the waiver is requested and describe the employees to be covered by the waiver;
 - (3) Contain the information required by § 40.21 of this title and any other information or arguments available to support the waiver requested; and
 - (4) Unless good cause is shown in the application, be submitted at least 60 days before the proposed effective date of the waiver.
- (c) No public hearing or other proceeding is held directly on an application before its disposition under this section. If the Associate Administrator determines that the application contains adequate justification, he or she grants the waiver. If the Associate Administrator determines that the application does not justify granting the waiver, he or she denies the application. The Associate Administrator notifies each applicant of the decision to grant or deny an application.

§ 199.9 Preemption of State and Local Laws

- (a) Except as provided in paragraph (b) of this section, this subpart preempts any State or local law, rule, regulation, or order to the extent that:
 - (1) Compliance with both the State or local requirement and this subpart is not possible;
 - (2) Compliance with the State or local requirement is an obstacle to the accomplishment and execution of any requirement in this subpart; or
 - (3) The State or local requirement is a pipeline safety standard applicable to interstate pipeline facilities.

- (b) This subpart shall not be construed to preempt provisions of State criminal law that impose sanctions for reckless conduct leading to actual loss of life, injury, or damage to property, whether the provisions apply specifically to transportation employees or employers or to the general public.

SUBPART B - DRUG TESTING

§ 199.100 Purpose

The purpose of this subpart is to establish programs designed to help prevent accidents and injuries resulting from the use of prohibited drugs by employees who perform covered functions for operators of certain pipeline facilities subject to part 192,~~193,~~ or 195 of this chapter.

§ 199.101 Anti-Drug Plan

- (a) Each operator shall maintain and follow a written anti-drug plan that conforms to the requirements of this subpart and the DOT Procedures. The plan must contain:
 - (1) Methods and procedures for compliance with all the requirements of this subpart, including the employee assistance program;
 - (2) The name and address of each laboratory that analyzes the specimens collected for drug testing;
 - (3) The name and address of the operator's Medical Review Officer, and Substance Abuse Professional; and
 - (4) Procedures for notifying employees of the coverage and provisions of the plan.
- (b) The Administrator or the State Agency that has submitted a current certification under the pipeline safety law (49 U.S.C. 60101 *et seq.*) with respect to the pipeline facility governed by an operator's plans and procedures may, after notice and opportunity for hearing as provided in 49 CFR 190.206 or the relevant State procedures, require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety.

§ 199.103 Use of Persons Who Fail or Refuse a Drug Test

- (a) An operator may not knowingly use as an employee any person who:
 - (1) Fails a drug test required by this subpart and the medical review officer makes a determination under DOT Procedures; or
 - (2) Refuses to take a drug test required by this subpart.
- (b) Paragraph (a)(1) of this section does not apply to a person who has:
 - (1) Passed a drug test under DOT Procedures;
 - (2) Been considered by the medical review officer in accordance with DOT Procedures and been determined by a substance abuse professional to have successfully completed required education or treatment; and
 - (3) Not failed a drug test required by this subpart after returning to duty.

§ 199.105 Drug Tests Required

Each operator shall conduct the following drug tests for the presence of a prohibited drug:

- (a) Pre-employment testing. No operator may hire or contract for the use of any person as an employee unless that person passes a drug test or is covered by an anti-drug program that conforms to the requirements of this subpart.
- (b) *Post-accident testing.*
 - (1) As soon as possible but no later than 32 hours after an accident, an operator must drug test each surviving covered employee whose performance of a covered function either contributed to the accident or cannot be completely discounted as a contributing factor to the accident. An operator may decide not to test under this paragraph, but such a decision must be based on specific information that the covered employee's performance had no role in the cause(s) or severity of the accident.
 - (2) If a test required by this section is not administered within the 32 hours following the accident, the operator must prepare and maintain its decision stating the reasons why the test was not promptly administered. If a test required by paragraph (b)(1) of this section is not administered within 32 hours following the accident, the operator must cease attempts to administer a drug test and must state in the record the reasons for not administering the test.
- (c) Random testing.
 - (1) Except as provided in paragraphs (c)(2) through (4) of this section, the minimum annual percentage rate for random drug testing shall be 50 percent of covered employees.
 - (2) The Administrator's decision to increase or decrease the minimum annual percentage rate for random drug testing is based on the reported positive rate for the entire industry. All information used for this determination is drawn from the drug MIS reports required by this subpart. In order to ensure reliability of the data, the Administrator considers the quality and completeness of the reported data, may obtain additional information or reports from operators, and may make appropriate modifications in calculating the industry positive rate. Each year, the Administrator will publish in the Federal Register the minimum annual percentage rate for random drug testing of covered employees. The new minimum annual percentage rate for random drug testing will be applicable starting January 1 of the calendar year following publication.
 - (3) When the minimum annual percentage rate for random drug testing is 50 percent, the Administrator may lower this rate to 25 percent of all covered employees if the Administrator determines that the data received under the reporting requirements of § 199.119 for two consecutive calendar years indicate that the reported positive rate is less than 1.0 percent.
 - (4) When the minimum annual percentage rate for random drug testing is 25 percent, and the data received under the reporting requirements of § 199.119 for any calendar year indicate that the reported positive rate is equal to or greater than 1.0 percent, the Administrator will increase the minimum annual percentage rate for random drug testing to 50 percent of all covered employees.
 - (5) The selection of employees for random drug testing shall be made by a scientifically valid method, such as a random number table or a computer-based random number generator that is matched with employees' Social Security numbers, payroll identification numbers, or other comparable identifying numbers. Under the selection process used, each covered employee shall have an equal

chance of being tested each time selections are made.

- (6) The operator shall randomly select a sufficient number of covered employees for testing during each calendar year to equal an annual percentage rate not less than the minimum annual percentage rate for random drug testing determined by the Administrator. If the operator conducts random drug testing through a consortium, the number of employees to be tested may be calculated for each individual operator or may be based on the total number of covered employees covered by the consortium who are subject to random drug testing at the same minimum annual percentage rate under this subpart or any DOT drug testing rule.
- (7) Each operator shall ensure that random drug tests conducted under this subpart are unannounced and that the dates for administering random tests are spread reasonably throughout the calendar year.
- (8) If a given covered employee is subject to random drug testing under the drug testing rules of more than one DOT agency for the same operator, the employee shall be subject to random drug testing at the percentage rate established for the calendar year by the DOT agency regulating more than 50 percent of the employee's function.
- (9) If an operator is required to conduct random drug testing under the drug testing rules of more than one DOT agency, the operator may-
 - (i) Establish separate pools for random selection, with each pool containing the covered employees who are subject to testing at the same required rate; or
 - (ii) Randomly select such employees for testing at the highest percentage rate established for the calendar year by any DOT agency to which the operator is subject.
- (d) Testing based on reasonable cause. Each operator shall drug test each employee when there is reasonable cause to believe the employee is using a prohibited drug. The decision to test must be based on a reasonable and articulable belief that the employee is using a prohibited drug on the basis of specific, contemporaneous physical, behavioral, or performance indicators of probable drug use. At least two of the employee's supervisors, one of whom is trained in detection of the possible symptoms of drug use, shall substantiate and concur in the decision to test an employee. The concurrence between the two supervisors may be by telephone. However, in the case of operators with 50 or fewer employees subject to testing under this subpart, only one supervisor of the employee trained in detecting possible drug use symptoms shall substantiate the decision to test.
- (e) Return-to-duty testing. A covered employee who refuses to take or has a positive drug test may not return to duty in the covered function until the covered employee has complied with applicable provisions of DOT Procedures concerning substance abuse professionals and the return-to-duty process.
- (f) Follow-up testing. A covered employee who refuses to take or has a positive drug test shall be subject to unannounced follow-up drug tests administered by the operator following the covered employee's the covered return to duty. The number and frequency of such follow-up testing shall be determined by a substance abuse professional but shall consist of at least six tests in the first 12 months following the covered employee's return to duty. In addition, follow-up testing may include testing for alcohol as directed by the substance abuse professional, to be performed in accordance with 49 CFR 40. Follow-up

testing shall not exceed 60 months from the date of the covered employee's return to duty. The substance abuse professional may terminate the requirement for follow-up testing at any time after the first six tests have been administered, if the substance abuse professional determines that such testing is no longer necessary.

§ 199.107 Drug Testing Laboratory

- (a) Each operator shall use for the drug testing required by this subpart only drug testing laboratories certified by the Department of Health and Human Services under the DOT Procedures.
- (b) The drug testing laboratory must permit:
 - (1) Inspections by the operator before the laboratory is awarded a testing contract; and
 - (2) Unannounced inspections, including examination of records, at any time, by the operator, the Administrator, and if the operator is subject to state agency jurisdiction, a representative of that state agency.

§ 199.109 Review of Drug Testing Results

- (a) *MRO appointment.* Each operator shall designate or appoint a medical review officer (MRO). If an operator does not have a qualified individual on staff to serve as MRO, the operator may contract for the provision of MRO services as part of its anti-drug program.
- (b) *MRO qualifications.* Each MRO must be a licensed physician who has the qualifications required by DOT Procedures.
- (c) *MRO duties.* The MRO must perform functions for the operator as required by DOT Procedures.
- (d) *MRO reports.* The MRO must report all drug test results to the operator in accordance with DOT Procedures.
- (e) Evaluation and rehabilitation may be provided by the operator, by a substance abuse professional under contract with the operator, or by a substance abuse professional not affiliated with the operator. The choice of substance abuse professional and assignment of costs shall be made in accordance with the operator/employee policies.
- (f) The operator shall ensure that a substance abuse professional, who determines that a covered employee requires assistance in resolving problems with drug abuse, does not refer the covered employee to the substance abuse professional's private practice or to a person or organization from which the substance abuse professional receives remuneration or in which the substance abuse professional has a financial interest. This paragraph does not prohibit a substance abuse professional from referring a covered employee for assistance provided through:
 - (1) A public agency, such as a State, county, or municipality;
 - (2) The operator or a person under contract to provide treatment for drug problems on behalf of the operator;
 - (3) The sole source of therapeutically appropriate treatment under the employee's health insurance program; or
 - (4) The sole source of therapeutically appropriate treatment reasonably accessible to the employee.

§ 199.111 [Removed and Reserved]

§ 199.113 Employee Assistance Program

- (a) Each operator shall provide an employee assistance program (EAP) for its employees and supervisory personnel who will determine whether an employee must be drug tested based on reasonable cause. The operator may establish the EAP as a part of its internal personnel services, or the operator may contract with an entity that provides EAP services. Each EAP must include education and training on drug use. At the discretion of the operator, the EAP may include an opportunity for employee rehabilitation.
- (b) Education under each EAP must include at least the following elements: display and distribution of informational material; display and distribution of a community service hot-line telephone number for employee assistance; and display and distribution of the employer's policy regarding the use of prohibited drugs.
- (c) Training under each EAP for supervisory personnel who will determine whether an employee must be drug tested based on reasonable cause must include one 60-minute period of training on the specific, contemporaneous physical, behavioral, and performance indicators of probable drug use.

§ 199.115 Contractor Employees

With respect to those employees who are contractors or employed by a contractor, an operator may provide by contract that the drug testing, education, and training required by this subpart be carried out by the contractor provided:

- (a) The operator remains responsible for ensuring that the requirements of this subpart are complied with; and
- (b) The contractor allows access to property and records by the operator, the Administrator, and if the operator is subject to the jurisdiction of a state agency, a representative of the state agency for the purpose of monitoring the operator's compliance with the requirements of this subpart.

§ 199.117 Record Keeping

- (a) Each operator shall keep the following records for the periods specified and permit access to the records as provided by paragraph (b) of this section:
 - (1) Records that demonstrate the collection process conforms to this subpart must be kept for at least 3 years.
 - (2) Records of employee drug test that indicate a verified positive result, records that demonstrate compliance with the recommendations of a substance abuse professional, and MIS annual report data shall be maintained for a minimum of five years.
 - (3) Records of employee drug test results that show employees passed a drug test must be kept for at least 1 year.
 - (4) Records confirming that supervisors and employees have been trained as required by this part must be kept for at least 3 years.
- (b) Information regarding an individual's drug testing results or rehabilitation must be released upon the written consent of the individual and as provided by DOT Procedures.

§ 199.119 Reporting of Anti-Drug Testing Results

- (a) Each large operator (having more than 50 covered employees) must submit an annual Management Information System (MIS) report to PHMSA of its anti-drug testing using the

MIS form and instructions as required by 49 CFR part 40 (at § 40.26 and appendix H to part 40), not later than March 15 of each year for the prior calendar year (January 1 through December 31). The Administrator may require by notice in the PHMSA Portal (<https://portal.phmsa.dot.gov/phmsaportallanding>) that small operators (50 or fewer covered employees), not otherwise required to submit annual MIS reports, to prepare and submit such reports to PHMSA.

- (b) Each report required under this section must be submitted electronically at <http://damis.dot.gov>. An operator may obtain the username and password needed for electronic reporting from the PHMSA Portal (<https://portal.phmsa.dot.gov/phmsaportallanding>). If electronic reporting imposes an undue burden and hardship, the operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE., Washington, DC 20590. PHMSA will review the request and may authorize, in writing, an alternative reporting method. The request must describe the undue burden and hardship. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202-366-8075, or electronically to informationresourcesmanager@dot.gov to make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received.
- (c) To calculate the total number of covered employees eligible for random testing throughout the year, as an operator, you must add the total number of covered employees eligible for testing during each random testing period for the year and divide that total by the number of random testing periods. Covered employees, and only covered employees, are to be in an employer's random testing pool, and all covered employees must be in the random pool. If you are an employer conducting random testing more often than once per month (e.g., you select daily, weekly, bi-weekly), you do not need to compute this total number of covered employees' rate more than on a once per month basis.
- (d) As an employer, you may use a service agent (e.g., C/TPA) to perform random selections for you; and your covered employees may be part of a larger random testing pool of covered employees. However, you must ensure that the service agent you use is testing at the appropriate percentage established for your industry and that only covered employees are in the random testing pool.
- (e) Each operator that has a covered employee who performs multi-DOT agency functions (e.g., an employee performs pipeline maintenance duties and drives a commercial motor vehicle), count the employee only on the MIS report for the DOT agency under which he or she is randomly tested. Normally, this will be the DOT agency under which the employee performs more than 50% of his or her duties. Operators may have to explain the testing data for these employees in the event of a DOT agency inspection or audit.
- (f) A service agent (e.g., Consortia/Third Party Administrator as defined in 49 CFR Part 40) may prepare the MIS report on behalf of an operator. However, each report shall be certified by the operator's anti-drug manager or designated representative for accuracy and completeness.

SUBPART C - ALCOHOL MISUSE PREVENTION PROGRAM

§ 199.200 Purpose

The purpose of this subpart is to establish programs designed to help prevent accidents and injuries resulting from the misuse of alcohol by employees who perform covered functions for operators of certain pipeline facilities subject to part 192 of this code.

§ 199.201 [Reserved]

§ 199.202 Alcohol Misuse Plan

Each operator must maintain and follow a written alcohol misuse plan that conforms to the requirements of this part and DOT Procedures concerning alcohol testing programs. The plan shall contain methods and procedures for compliance with all the requirements of this subpart, including required testing, record keeping, reporting, education and training elements.

§§ 199.203-199.205 [Reserved]

§ 199.209 Other Requirements Imposed by Operators

- (a) Except as expressly provided in this subpart, nothing in this subpart shall be construed to affect the authority of operators, or the rights of employees, with respect to the use or possession of alcohol, including authority and rights with respect to alcohol testing and rehabilitation.
- (b) Operators may, but are not required to, conduct pre-employment alcohol testing under this subpart. Each operator that conducts pre-employment alcohol testing must-
 - (1) Conduct a pre-employment alcohol test before the first performance of covered functions by every covered employee (whether a new employee or someone who has transferred to a position involving the performance of covered functions);
 - (2) Treat all covered employees the same for the purpose of pre-employment alcohol testing (i.e., you must not test some covered employees and not others);
 - (3) Conduct the pre-employment tests after making a contingent offer of employment or transfer, subject to the employee passing the pre-employment alcohol test;
 - (4) Conduct all pre-employment alcohol tests using the alcohol testing procedures in DOT Procedures; and
 - (5) Not allow any covered employee to begin performing covered functions unless the result of the employee's test indicates an alcohol concentration of less than 0.04.

§ 199.211 Requirements for Notice

Before performing an alcohol test under this subpart, each operator shall notify a covered employee that the alcohol test is required by this subpart. No operator shall falsely represent that a test is administered under this subpart.

§ 199.213 [Reserved]

§ 199.215 Alcohol Concentration

Each operator shall prohibit a covered employee from reporting for duty or remaining on duty requiring the performance of covered functions while having an alcohol concentration of 0.04 or greater. No operator having actual knowledge that a covered employee has an alcohol concentration of 0.04 or greater shall permit the employee to perform or continue to perform covered functions.

§ 199.217 On-duty Use

Each operator shall prohibit a covered employee from using alcohol while performing covered functions. No operator having actual knowledge that a covered employee is using alcohol while performing covered

functions shall permit the employee to perform or continue to perform covered functions.

§ 199.219 Pre-duty Use

Each operator shall prohibit a covered employee from using alcohol within four hours prior to performing covered functions, or, if an employee is called to duty to respond to an emergency, within the time period after the employee has been notified to report for duty. No operator having actual knowledge that a covered employee has used alcohol within four hours prior to performing covered functions or within the time period after the employee has been notified to report for duty shall permit that covered employee to perform or continue to perform covered functions.

§ 199.221 Use Following an Accident

Each operator shall prohibit a covered employee who has actual knowledge of an accident in which his or her performance of covered functions has not been discounted by the operator as a contributing factor to the accident from using alcohol for eight hours following the accident, unless he or she has been given a post-accident test under § 199.225(a), or the operator has determined that the employee's performance could not have contributed to the accident.

§ 199.223 Refusal to Submit to a Required Alcohol Test

Each operator shall require a covered employee to submit to a post-accident alcohol test required under § 199.225(a), a reasonable suspicion alcohol test required under § 199.225(b), or a follow-up alcohol test required under § 199.225(d). No operator shall permit an employee who refuses to submit to such a test to perform or continue to perform covered functions.

§ 199.225 Alcohol Tests Required

Each operator shall conduct the following types of alcohol tests for the presence of alcohol:

- (a) Post-accident.
 - (1) As soon as practicable following an accident, each operator must test each surviving covered employee for alcohol if that employee's performance of a covered function either contributed to the accident or cannot be completely discounted as a contributing factor to the accident. The decision not to administer a test under this section must be based on specific information that the covered employee's performance had no role in the cause(s) or severity of the accident.
 - (2) (i) If a test required by this section is not administered within two hours following the accident, the operator shall prepare and maintain on file a record stating the reasons the test was not promptly administered. If a test required by paragraph (a) is not administered within eight hours following the accident, the operator shall cease attempts to administer an alcohol test and shall state in the record the reasons for not administering the test.
~~(iii)(i)~~ [Removed and Reserved].
 - ~~(3)(2)~~ A covered employee who is subject to post-accident testing who fails to remain readily available for such testing, including notifying the operator or operator representative of his/her location if he/she leaves the scene of the accident prior to submission to such test, may be deemed by the operator to have refused to submit to testing. Nothing in this section shall be construed to require the delay of necessary medical attention for injured people following an accident or to prohibit a covered employee from leaving the scene of an accident for the period necessary to obtain assistance in responding to the accident or to obtain necessary emergency medical care.
- (b) Reasonable suspicion testing.

- (1) Each operator shall require a covered employee to submit to an alcohol test when the operator has reasonable suspicion to believe that the employee has violated the prohibitions in this subpart.
 - (2) The operator's determination that reasonable suspicion exists to require the covered employee to undergo an alcohol test shall be based on specific, contemporaneous, articulable observations concerning the appearance, behavior, speech, or body odors of the employee. The required observations shall be made by a supervisor who is trained in detecting the symptoms of alcohol misuse. The supervisor who makes the determination that reasonable suspicion exists shall not conduct the breath alcohol test on that employee.
 - (3) Alcohol testing is authorized by this section only if the observations required by subparagraph (b)(2) of this paragraph are made during, just preceding, or just after the period of the workday that the employee is required to be in compliance with this subpart. A covered employee may be directed by the operator to undergo reasonable suspicion testing for alcohol only while the employee is performing covered functions; just before the employee is to perform covered functions; or just after the employee has ceased performing covered functions.
 - (4)
 - (i) If a test required by this paragraph is not administered within two hours following the determination under subparagraph (b)(2) of this paragraph, the operator shall prepare and maintain on file a record stating the reasons the test was not promptly administered. If a test required by this paragraph is not administered within eight hours following the determination under subparagraph (b)(2) of this paragraph, the operator shall cease attempts to administer an alcohol test and shall state in the record the reasons for not administering the test. Records shall be submitted to PHMSA upon request of the Administrator.
 - (ii) [Removed and Reserved].
 - (iii) Notwithstanding the absence of a reasonable suspicion alcohol test under this paragraph, an operator shall not permit a covered employee to report for duty or remain on duty requiring the performance of covered functions while the employee is under the influence of or impaired by alcohol, as shown by the behavioral, speech, or performance indicators of alcohol misuse, nor shall an operator permit the covered employee to perform or continue to perform covered functions, until:
 - (A) An alcohol test is administered and the employee's alcohol concentration measures less than 0.02; or
 - (B) The start of the employee's next regularly scheduled duty period, but not less than 8 hours following the determination under subparagraph (b)(2) of this paragraph that there is reasonable suspicion to believe that the employee has violated the prohibitions in this subpart.
 - (iv) Except as provided in subparagraph (b)(4)(ii), no operator shall take any action under this subpart against a covered employee based solely on the employee's behavior and appearance in the absence of an alcohol test. This does not prohibit an operator with the authority independent of this subpart from taking any action otherwise consistent with law.
- (c) *Return-to-duty testing.* Each operator shall ensure that before a covered employee

returns to duty requiring the performance of a covered function after engaging in conduct prohibited by §§ 199.215 through 199.223, the employee shall undergo a return-to-duty alcohol test with a result indicating an alcohol concentration of less than 0.02.

- (d) *Follow-up testing.*
 - (1) Following a determination under § 199.243(b) that a covered employee is in need of assistance in resolving problems associated with alcohol misuse, each operator shall ensure that the employee is subject to unannounced follow-up alcohol testing as directed by a substance abuse professional in accordance with the provisions of § 199.243(c)(2)(ii).
 - (2) Follow-up testing shall be conducted when the covered employee is performing covered functions; just before the employee is to perform covered functions; or just after the employee has ceased performing such functions.
- (e) *Retesting of covered employees with an alcohol concentration of 0.02 or greater but less than 0.04.* Each operator shall retest a covered employee to ensure compliance with the provisions of § 199.237, if an operator chooses to permit the employee to perform a covered function within eight hours following the administration of an alcohol test indicating an alcohol concentration of 0.02 or greater but less than 0.04.

§ 199.227 Retention of Records

- (a) General requirement. Each operator shall maintain records of its alcohol misuse prevention program as provided in this paragraph. The records shall be maintained in a secure location with controlled access.
- (b) Period of retention. Each operator shall maintain the records in accordance with the following schedule:
 - (1) Five years. Records of employee alcohol test results with results indicating an alcohol concentration of 0.02 or greater, documentation of refusals to take required alcohol tests, calibration documentation, employee evaluation and referrals, and MIS annual report data shall be maintained for a minimum of five years.
 - (2) Two years. Records related to the collection process (except calibration of evidential breath testing devices), and training shall be maintained for a minimum of two years.
 - (3) One year. Records of all test results below 0.02 (as defined in 49 CFR Part 40) shall be maintained for a minimum of one year.
 - (4) Three years. Records of decisions not to administer post-accident employee alcohol tests must be kept for a minimum of three years.
- (c) Types of records. The following specific records shall be maintained:
 - (1) Records related to the collection process:
 - (i) Collection logbooks, if used.
 - (ii) Calibration documentation for evidential breath testing devices.
 - (iii) Documentation of breath alcohol technician training.
 - (iv) Documents generated in connection with decisions to administer reasonable suspicion alcohol tests.
 - (v) Documents generated in connection with decisions on post-accident tests.

- (vi) Documents verifying existence of a medical explanation of the inability of a covered employee to provide adequate breath for testing.
- (2) Records related to test results:
 - (i) The operator's copy of the alcohol test form, including the results of the test.
 - (ii) Documents related to the refusal of any covered employee to submit to an alcohol test required by this subpart.
 - (iii) Documents presented by a covered employee to dispute the result of an alcohol test administered under this subpart.
- (3) Records related to other violations of this subpart.
- (4) Records related to evaluations:
 - (i) Records pertaining to a determination by a substance abuse professional concerning a covered employee's need for assistance.
 - (ii) Records concerning a covered employee's compliance with the recommendations of the substance abuse professional.
- (5) Record(s) related to the operator's MIS annual testing data.
- (6) Records related to education and training:
 - (i) Materials on alcohol misuse awareness, including a copy of the operator's policy on alcohol misuse.
 - (ii) Documentation of compliance with the requirements of § 199.231.
 - (iii) Documentation of training provided to supervisors for the purpose of qualifying the supervisors to make a determination concerning the need for alcohol testing based on reasonable suspicion.
 - (iv) Certification that any training conducted under this subpart complies with the requirements for such training.

§ 199.229 Reporting of Alcohol Testing Results

- (a) Each large operator (having more than 50 covered employees) must submit an annual MIS report to PHMSA of its alcohol testing results using the MIS form and instructions as required by 49 CFR part 40 (at § 40.26 and appendix H to part 40) not later than March 15 of each year for the prior calendar year (January 1 through December 31). The Administrator may require by notice in the PHMSA Portal (<https://portal.phmsa.dot.gov/phmsaportallanding>) that small operators (50 or fewer covered employees), not otherwise required to submit annual MIS reports, to prepare and submit such reports to PHMSA.
- (b) Each operator that has a covered employee who performs multi-DOT agency functions (e.g., an employee performs pipeline maintenance duties and drives a commercial motor vehicle), count the employee only on the MIS report for the DOT agency under which he or she is tested. Normally, this will be the DOT agency under which the employee performs more than 50% of his or her duties. Operators may have to explain the testing data for these employees in the event of a DOT agency inspection or audit.
- (c) Each report required under this section must be submitted electronically at <http://damis.dot.gov>. An operator may obtain the user name and password needed for electronic reporting from the PHMSA Portal

<https://portal.phmsa.dot.gov/phmsaortallanding>. If electronic reporting imposes an undue burden and hardship, the operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE., Washington, DC 20590. The request must describe the undue burden and hardship. PHMSA will review the request and authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202- 366-8075, or electronically to informationresourcesmanager@dot.gov to make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received.

- (d) A service agent (e.g., Consortia/Third Party Administrator as defined in Part 40) may prepare the MIS report on behalf of an operator. However, each report shall be certified by the operator's anti-drug manager or designated representative for accuracy and completeness.

§ 199.231 Access to Facilities and Records

- (a) Except as required by law or expressly authorized or required in this subpart, no employer shall release covered employee information that is contained in records required to be maintained in § 199.227.
- (b) A covered employee is entitled, upon written request, to obtain copies of any records pertaining to the employee's use of alcohol, including any records pertaining to his or her alcohol tests. The operator shall promptly provide the records requested by the employee. Access to an employee's records shall not be contingent upon payment for records other than those specifically requested.
- (c) Each operator shall permit access to all facilities utilized in complying with the requirements of this subpart to the Secretary of Transportation, any DOT agency, or a representative of a state agency with regulatory authority over the operator.
- (d) Each operator shall make available copies of all results for employer alcohol testing conducted under this subpart and any other information pertaining to the operator's alcohol misuse prevention program, when requested by the Secretary of Transportation, any DOT agency with regulatory authority over the operator, or a representative of a state agency with regulatory authority over the operator. The information shall include name-specific alcohol test results, records, and reports.
- (e) When requested by the National Transportation Safety Board as part of an accident investigation, an operator shall disclose information related to the operator's administration of any post-accident alcohol tests administered following the accident under investigation.
- (f) An operator shall make records available to a subsequent employer upon receipt of the written request from the covered employee. Disclosure by the subsequent employer is permitted only as expressly authorized by the terms of the employee's written request.
- (g) An operator may disclose information without employee consent as provided by DOT Procedures concerning certain legal proceedings.
- (h) An operator shall release information regarding a covered employee's records as directed by the specific, written consent of the employee authorizing release of the information to an identified person. Release of such information by the person receiving the information is permitted only in accordance with the terms of the employee's consent.

§ 199.233 Removal from Covered Function

Except as provided in §§ 199.239 through 199.243, no operator shall permit any covered employee to perform covered functions if the employee has engaged in conduct prohibited by §§ 199.215 through 199.223 or an alcohol misuse rule of another DOT agency.

§ 199.235 Required Evaluation and Testing

No operator shall permit a covered employee who has engaged in conduct prohibited by §§ 199.215 through 199.223 to perform covered functions unless the employee has met the requirements of § 199.243.

§ 199.237 Other Alcohol-related Conduct

- (a) No operator shall permit a covered employee tested under the provisions of § 199.225, who is found to have an alcohol concentration of 0.02 or greater but less than 0.04, to perform or continue to perform covered functions, until:
 - (1) The employee's alcohol concentration measures less than 0.02 in accordance with a test administered under § 199.225(e); or
 - (2) The start of the employee's next regularly scheduled duty period, but not less than eight hours following administration of the test.
- (b) Except as provided in paragraph (a) of this section, no operator shall take any action under this subpart against an employee based solely on test results showing an alcohol concentration less than 0.04. This does not prohibit an operator with authority independent of this subpart from taking any action otherwise consistent with law.

§ 199.239 Operator Obligation to Promulgate a Policy on the Misuse of Alcohol

- (a) General requirement. Each operator shall provide educational materials that explain these alcohol misuse requirements and the operator's policies and procedures with respect to meeting those requirements.
 - (1) The operator shall ensure that a copy of these materials is distributed to each covered employee prior to the start of alcohol testing under this subpart, and to each person subsequently hired for or transferred to a covered position.
 - (2) Each operator shall provide written notice to representatives of employee organizations of the availability of this information.
- (b) Required content. The materials to be made available to covered employees shall include detailed discussion of at least the following:
 - (1) The identity of the person designated by the operator to answer covered employee's questions about the materials.
 - (2) The categories of employees who are subject to the provisions of this subpart.
 - (3) Sufficient information about the covered functions performed by those employees to make clear what period of the workday the covered employee is required to be in compliance with this subpart.
 - (4) Specific information concerning covered employee conduct that is prohibited by this subpart.
 - (5) The circumstances under which a covered employee will be tested for alcohol under this subpart.
 - (6) The procedures that will be used to test for the presence of alcohol, protect the covered employee and the integrity of the breath testing process, safeguard the validity of the test results, and ensure that those results are attributed to the correct

employee.

- (7) The requirement that a covered employee submit to alcohol tests administered in accordance with this subpart.
 - (8) An explanation of what constitutes a refusal to submit to an alcohol test and the attendant consequences.
 - (9) The consequences for covered employees found to have violated the prohibitions under this subpart, including the requirement that the employee be removed immediately from covered functions, and the procedures under § 199.243.
 - (10) The consequences for covered employees found to have an alcohol concentration of 0.02 or greater but less than 0.04.
 - (11) Information concerning the effects of alcohol misuse on an individual's health, work, and personal life; signs and symptoms of an alcohol problem (the employee's or a coworker's); and including intervening evaluating and resolving problems associated with the misuse of alcohol including intervening when an alcohol problem is suspected, confrontation, referral to any available EAP, and/or referral to management.
- (c) Optional provisions. The materials supplied to covered employees may also include information on additional operator policies with respect to the use or possession of alcohol, including any consequences for an employee found to have a specified alcohol level, that are based on the operator's authority independent of this subpart. Any such additional policies or consequences shall be clearly described as being based on independent authority.

§ 199.241 Training for Supervisors

Each operator shall ensure that persons designated to determine whether reasonable suspicion exists to require a covered employee to undergo alcohol testing under § 199.225(b) receive at least 60 minutes of training on the physical, behavioral, speech, and performance indicators of probable alcohol misuse.

§ 199.243 Referral, Evaluation, and Treatment

- (a) Each covered employee who has engaged in conduct prohibited by §§ 199.215 through 199.223 of this subpart shall be advised of the resources available to the covered employee in evaluating and resolving problems associated with the misuse of alcohol, including the names, addresses, and telephone numbers of substance abuse professionals and counseling and treatment programs.
- (b) Each covered employee who engages in conduct prohibited under §§ 199.215 through 199.223 shall be evaluated by a substance abuse professional who shall determine what assistance, if any, the employee needs in resolving problems associated with alcohol misuse.
- (c)
 - (1) Before a covered employee returns to duty requiring the performance of a covered function after engaging in conduct prohibited by §§ 199.215 through 199.223 of this subpart, the employee shall undergo a return-to-duty alcohol test with a result indicating an alcohol concentration of less than 0.02.
 - (2) In addition, each covered employee identified as needing assistance in resolving problems associated with alcohol misuse:
 - (i) Shall be evaluated by a substance abuse professional to determine that the employee has properly followed any rehabilitation program prescribed under paragraph (b) of this section.

- (ii) Shall be subject to unannounced follow-up alcohol tests administered by the operator following the employee's return to duty. The number and frequency of such follow-up testing shall be determined by a substance abuse professional but shall consist of at least six tests in the first 12 months following the employee's return to duty. In addition, follow-up testing may include testing for drugs, as directed by the substance abuse professional, to be performed in accordance with 49 CFR Part 40. Follow-up testing shall not exceed 60 months from the date of the employee's return to duty. The substance abuse professional may terminate the requirement for follow-up testing at any time after the first six tests have been administered, if the substance abuse professional determines that such testing is no longer necessary.
- (d) Evaluation and rehabilitation may be provided by the operator, by a substance abuse professional under contract with the operator, or by a substance abuse professional not affiliated with the operator. The choice of substance abuse professional and assignment of costs shall be made in accordance with the operator/employee agreements and operator/employee policies.
- (e) The operator shall ensure that a substance abuse professional who determines that a covered employee requires assistance in resolving problems with alcohol misuse does not refer the employee to the substance abuse professional's private practice or to a person or organization from which the substance abuse professional receives remuneration or in which the substance abuse professional has a financial interest. This paragraph does not prohibit a substance abuse professional from referring an employee for assistance provided through:
 - (1) A public agency, such as a State, county, or municipality;
 - (2) The operator or a person under contract to provide treatment for alcohol problems on behalf of the operator;
 - (3) The sole source of therapeutically appropriate treatment under the employee's health insurance program; or
 - (4) The sole source of therapeutically appropriate treatment reasonably accessible to the employee.

§ 199.245 Contractor Employees

- (a) With respect to those covered employees who are contractors or employed by a contractor, an operator may provide by contract that the alcohol testing, training and education required by this subpart be carried out by the contractor provided:
- (b) The operator remains responsible for ensuring that the requirements of this subpart and 49 CFR Part 40 are complied with; and
- (c) The contractor allows access to property and records by the operator, the Administrator, any DOT agency with regulatory authority over the operator or covered employee, and if the operator is subject to the jurisdiction of a state agency, a representative of the state agency for the purposes of monitoring the operator's compliance with the requirements of this subpart and 49 CFR Part 40.

BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF PROPOSED)
REVISIONS TO THE ARKANSAS) **DOCKET NO. 25-025-R**
GAS PIPELINE CODE)

EXHIBIT 4
REVISED CLEAN VERSION OF ARKANSAS PIPELINE SAFETY CODE

**ARKANSAS
PUBLIC SERVICE COMMISSION**



**ARKANSAS GAS PIPELINE CODE
FOR
DESIGN, CONSTRUCTION, OPERATION INSPECTION AND
MAINTENANCE
OF NATURAL GAS SYSTEMS**

August , 2025
REVISED Docket No. 25-025-R

Table of Contents

PREFACE.....	16
ADMINISTRATIVE HISTORY	17
DEFINITIONS.....	22
PART 190-PIPELINE SAFETY ENFORCEMENT PROCEDURES.....	27
SUBPART A - GENERAL	27
§ 190.1 Purpose.....	27
§ 190.3 Service	27
§ 190.5 Subpoenas; Witness Fees.....	27
§ 190.7 Extension of Time	27
§ 190.9 Petitions for Finding or Approval	27
§ 190.11 Waivers	28
SUBPART B - ENFORCEMENT	28
§ 190.15 Inspections, Production of Records, and Accident Investigations.....	28
§ 190.17 Notice of Probable Violation	28
§ 190.19 Show Cause Orders.....	29
§ 190.21 Response Options	29
§ 190.23 Case File	29
§ 190.25 Final Order.....	29
§ 190.27 Petitions for Reconsideration.....	29
§ 190.29 Civil Penalties	30
§ 190.31 Payment of Civil Penalties	30
SUBPART C - SPECIFIC RELIEF	30
§ 190.41 Hazardous Conditions.....	30
§ 190.43 Injunctive Action	30
PART 191 - TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE.....	31
ANNUAL REPORTS, INCIDENT REPORTS, AND SAFETY-RELATED CONDITION REPORTS	31
§ 191.1 Scope	31
§ 191.5 Immediate Notice of Certain Incidents	31
§ 191.7 Report Submission Requirements.....	32
§ 191.9 Distribution System: Incident Report.....	32
§ 191.11 Distribution System: Annual Report	33
§ 191.12 [Removed and Reserved].....	33
§ 191.13 Distribution Systems Reporting Transmission Pipelines: Transmission or Gathering Systems Reporting Distribution Pipelines.....	33
§ 191.15 Transmission Systems; Gathering Systems; and Liquefied Natural Gas Facilities: Incident Report.....	33

§ 191.17 Transmission Systems; Gathering Systems; and Liquefied Natural Gas Facilities: Annual Report.....	33
§ 191.21 OMB Control Number Assigned to Information Collection.....	34
§ 191.22 National Registry of Pipeline operators	34
§ 191.23 Reporting Safety-Related Conditions.....	35
§ 191.25 Filing Safety-Related Condition Reports.....	36
§ 191.27 Status of Leaks.....	37
§ 191.29 National Pipeline Mapping System	38
APPENDIX A TO PART 191- PROCEDURE FOR DETERMINING REPORTING THRESHOLD	39
PART 192 - TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM SAFETY STANDARDS	40
SUBPART A – GENERAL	40
§ 192.1 Scope	40
§ 192.3 Definitions.....	40
§ 192.5 Class Locations.....	44
§ 192.7 What documents are incorporated by reference partly or wholly in this part?	45
§ 192.8 How are onshore gathering lines and regulated onshore gathering lines determined?	49
§ 192.9 What requirements apply to gathering lines?.....	51
§ 192.11 Petroleum Gas Systems	52
§ 192.13 What general requirements apply to pipelines regulated under this part?	53
§ 192.14 Conversion to Service Subject to this Part	53
§ 192.15 Rules of Regulatory Construction	54
§ 192.16 Customer Notification.....	54
§ 192.17 Filing of Operation, Inspection, and Maintenance Plan.....	55
§ 192.18 How to Notify PHMSA.....	55
SUBPART B – MATERIALS.....	55
§ 192.51 Scope	55
§ 192.53 General.....	56
§ 192.55 Steel Pipe	56
§ 192.57 [Removed and Reserved]	56
§ 192.59 Plastic Pipe.....	56
§ 192.61 [Removed and Reserved]	57
§ 192.63 Marking of Materials	57
§ 192.65 Transportation of Pipe.....	58
§192.67 Records: Material properties	58
§192.69 Storage and Handling of Plastic Pipe and Associated Components	58
SUBPART C - PIPE DESIGN	59
§ 192.101 Scope	59

§ 192.103	General	59
§ 192.105	Design Formula for Steel Pipe	59
§ 192.107	Yield Strength (S) for Steel Pipe	59
§ 192.109	Nominal Wall Thickness (t) for Steel Pipe.....	60
§ 192.111	Design Factor (F) for Steel Pipe.....	60
§ 192.112	Additional Design Requirements for Steel Pipe Using Alternative Maximum Allowable Operating Pressure	60
§ 192.113	Longitudinal Joint Factor (E) for Steel Pipe	63
§ 192.115	Temperature Derating Factor (T) for Steel Pipe	64
§ 192.117	[Removed and Reserved].....	64
§ 192.119	[Removed and Reserved].....	64
§ 192.121	Design of Plastic Pipe	64
§ 192.123	[Removed and Reserved].....	68
§ 192.125	Design of Copper Pipe	68
§ 192.127	Records: Pipe Design.....	68
SUBPART D - DESIGN OF PIPELINE COMPONENTS		69
§ 192.141	Scope.....	69
§ 192.143	General Requirements	69
§ 192.144	Qualifying Metallic Components	69
§ 192.145	Valves.....	69
§ 192.147	Flanges and Flange Accessories.....	70
§ 192.149	Standard Fittings	70
§ 192.150	Passage of Internal Inspection Devices.....	71
§ 192.151	Tapping.....	71
§ 192.153	Components Fabricated by Welding.....	72
§ 192.155	Welded Branch Connections	74
§ 192.157	Extruded Outlets.....	74
§ 192.159	Flexibility	74
§ 192.161	Supports and Anchors.....	74
§ 192.163	Compressor Stations: Design and Construction.....	75
§ 192.165	Compressor Stations: Liquid Removal.....	76
§ 192.167	Compressor Station: Emergency Shut-Down.....	76
§ 192.169	Compressor Stations: Pressure Limiting Devices	76
§ 192.171	Compressor Stations: Additional Safety Equipment	76
§ 192.173	Compressor Stations: Ventilation.....	77
§ 192.175	Pipe-Type and Bottle-Type Holders.....	77
§ 192.177	Additional Provisions for Bottle-Type Holders	77

§ 192.179	Transmission Line Valves	78
§ 192.181	Distribution Line Valves	79
§ 192.183	Vaults: Structural Design Requirements	79
§ 192.185	Vaults: Accessibility	79
§ 192.187	Vaults: Sealing, Venting, and Ventilation	79
§ 192.189	Vaults: Drainage and Waterproofing	80
§ 192.191	[Removed and Reserved].....	80
§ 192.193	Valve Installation in Plastic Pipe.....	80
§ 192.195	Protection Against Accidental Overpressuring.....	80
§ 192.197	Control of Pressure of Gas Delivered from High-Pressure Distribution Systems.....	80
§ 192.199	Requirements for Design of Pressure Relief and Limiting Devices	81
§ 192.201	Required Capacity of Pressure Relieving and Limiting Stations	82
§ 192.203	Instrument, Control, and Sampling Pipe and Components.....	83
§ 192.204	Risers Installed After January 22, 2019	83
§ 192.205	Records: Pipeline Components.....	83
SUBPART E - WELDING OF STEEL IN PIPELINES.....		84
§ 192.221	Scope.....	84
§ 192.225	Welding - Procedures.....	84
§ 192.227	Qualification of Welders and Welding Operators.....	84
§ 192.229	Limitations on Welders and Welding Operators	85
§ 192.231	Protection from Weather	85
§ 192.233	Miter Joints	85
§ 192.235	Preparation for Welding	86
§ 192.241	Inspection and Test of Welds.....	86
§ 192.243	Nondestructive Testing	86
§ 192.245	Repair or Removal of Defects.....	87
SUBPART F - JOINING OF MATERIALS OTHER THAN BY WELDING		87
§ 192.271	Scope.....	87
§ 192.273	General.....	87
§ 192.275	Cast Iron Pipe	88
§ 192.277	Ductile Iron Pipe	88
§ 192.279	Copper Pipe	88
§ 192.281	Plastic Pipe.....	88
§ 192.283	Plastic Pipe: Qualifying Joining Procedures	89
§ 192.285	Plastic Pipe: Qualifying Persons To Make Joints	90
§ 192.287	Plastic Pipe: Inspection of Joints	91
SUBPART G - GENERAL CONSTRUCTION REQUIREMENTS FOR TRANSMISSION LINES AND MAINS.....		91

§ 192.301	Scope.....	91
§ 192.303	Compliance with Specifications or Standards	91
§ 192.305	Inspection: General.....	91
§ 192.307	Inspection of Materials	91
§ 192.309	Repair of Steel Pipe.....	91
§ 192.311	Repair of Plastic Pipe	92
§ 192.313	Bends and Elbows	92
§ 192.315	Wrinkle Bends in Steel Pipe	93
§ 192.317	Protection from Hazards.....	93
§ 192.319	Installation of Pipe in a Ditch.....	93
§ 192.321	Installation of Plastic Pipe.....	94
§ 192.323	Casing	95
§ 192.325	Underground Clearance.....	95
§ 192.327	Cover.....	95
§ 192.328	Additional Construction Requirements for Steel Pipe Using Alternative Maximum Allowable Operating Pressure	96
§192.329	Installation Of Plastic Pipelines By Trenchless Excavation	97
SUBPART H - CUSTOMER METERS, SERVICE REGULATORS, AND SERVICE LINES.....		97
§ 192.351	Scope.....	97
§ 192.353	Customer Meters and Regulators: Location.....	97
§ 192.355	Customer Meters and Regulators: Protection from Damage	97
§ 192.357	Customer Meters and Regulators: Installation	98
§ 192.359	Customer Meter Installations: Operating Pressure	98
§ 192.361	Service Lines: Installation.....	98
§ 192.363	Service Lines: Valve Requirements.....	99
§ 192.365	Service Lines: Location of Valves	99
§ 192.367	Service Lines: General Requirements for Connections to Main Piping.....	99
§ 192.369	Service Lines: Connection to Cast Iron or Ductile Iron Mains	100
§ 192.371	Service Lines: Steel.....	100
§ 192.373	Service Lines: Cast Iron and Ductile Iron	100
§ 192.375	Service Lines: Plastic	100
§192.376	Installation Of Plastic Service Lines By Trenchless Excavation	100
§ 192.377	Service Lines: Copper	101
§ 192.379	New Service Lines Not in Use	101
§ 192.381	Service Lines: Excess Flow Valve Performance Standards.....	101
§ 192.383	Excess Flow Valve Installation.....	102
§ 192.385	Manual service line shut-off valve installation.....	102
SUBPART I - REQUIREMENTS FOR CORROSION CONTROL		104

§ 192.451	Scope.....	104
§ 192.452	How does this subpart apply to converted pipelines and regulated onshore gathering lines?.....	104
§ 192.453	General.....	104
§ 192.455	External Corrosion Control: Buried or Submerged Pipelines Installed After July 31, 1971	104
§ 192.457	External Corrosion Control: Buried or Submerged Pipelines Installed Before August 1, 1971	105
§ 192.459	External Corrosion Control: Examination of Buried Pipeline when Exposed.....	105
§ 192.461	External Corrosion Control: Protective Coating	106
§ 192.463	External Corrosion Control: Cathodic Protection	106
§ 192.465	External Corrosion Control: Monitoring.....	106
§ 192.467	External Corrosion Control: Electrical Isolation.....	107
§ 192.469	External Corrosion Control: Test Stations	108
§ 192.471	External Corrosion Control: Test Leads.....	108
§ 192.473	External Corrosion Control: Interference Currents	108
§ 192.475	Internal Corrosion Control: General	108
§ 192.476	Internal Corrosion Control: Design and Construction of Transmission Line.....	108
§ 192.477	Internal Corrosion Control: Monitoring.....	109
§ 192.479	Atmospheric Corrosion Control: General	109
§ 192.481	Atmospheric Corrosion Control: Monitoring.....	109
§ 192.483	Remedial Measures: General	110
§ 192.485	Remedial Measures: Transmission Lines	110
§ 192.487	Remedial Measures: Distribution Lines Other Than Cast Iron or Ductile Iron Lines ..	110
§ 192.489	Remedial Measures: Cast Iron and Ductile Iron Pipelines.....	111
§ 192.490	Direct Assessment	111
§ 192.491	Corrosion Control Records.....	111
§ 192.493	In-Line Inspection of Pipelines.....	112
SUBPART J - TEST REQUIREMENTS.....		112
§ 192.501	Scope.....	112
§ 192.503	General Requirements	112
§ 192.505	Strength Test Requirements for Steel Pipeline to Operate at a Hoop Stress of 30 Percent or More of SMYS	113
§ 192.506	Transmission Lines: Spike Hydrostatic Pressure Test	113
§ 192.507	Test Requirements for Pipelines to Operate at a Hoop Stress Less Than 30 Percent of SMYS and at or Above 100 P.S.I. (689 kPa) Gage.....	114
§ 192.509	Test Requirements for Pipelines to Operate Below 100 P.S.I. (689 kPa) Gage.....	114
§ 192.511	Test Requirements for Service Lines	115
§ 192.513	Test Requirements for Plastic Pipelines.....	115

§ 192.515 Environmental Protection and Safety Requirements	115
§ 192.517 Records: Tests.....	116
SUBPART K - UPRATING	116
§ 192.551 Scope.....	116
§ 192.553 General Requirements	116
§ 192.555 Uprating to a Pressure That Will Produce a Hoop Stress of 30 Percent or More of SMYS in Steel Pipelines	117
§ 192.557 Uprating Steel Pipelines to a Pressure That Will Produce a Hoop Stress Less Than 30 Percent of SMYS: Plastic, Cast Iron, and Ductile Iron Pipelines.....	117
SUBPART L - OPERATIONS.....	119
§ 192.601 Scope.....	119
§ 192.603 General Provisions.....	119
§ 192.605 Procedural Manual for Operations, Maintenance, and Emergencies	119
§ 192.607 Verification of Pipeline Material Properties And Attributes: Onshore Steel Transmission Pipelines.....	121
§ 192.609 Change in Class Location: Required Study.....	123
§ 192.611 Change in Class Location: Confirmation or Revision of Maximum Allowable Operating Pressure.....	124
§ 192.613 Continuing Surveillance	125
§ 192.614 Damage Prevention Program	125
§ 192.615 Emergency Plans	126
§ 192.616 Public Awareness.....	127
§ 192.617 Investigation of Failures.....	128
§ 192.619 Maximum Allowable Operating Pressure: Steel or Plastic Pipelines.....	128
§ 192.620 Alternative Maximum Allowable Operating Pressure for Certain Steel Pipelines	130
§ 192.621 Maximum Allowable Operating Pressure: High-Pressure Distribution Systems.....	137
§ 192.622 Maximum Actual Operating Pressure: High-Pressure Distribution Systems.....	138
§ 192.623 Maximum and Minimum Allowable Operating Pressure: Low-Pressure Distribution Systems.....	138
§ 192.624 Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines	139
§ 192.625 Odorization of Gas	142
§ 192.627 Tapping Pipelines Under Pressure.....	143
§ 192.629 Purging of Pipelines.....	143
§ 192.631 Control Room Management	143
§ 192.632 Engineering Critical Assessment for Maximum Allowable Operating Pressure Reconfirmation: Onshore steel transmission pipelines	147
SUBPART M - MAINTENANCE.....	149
§ 192.701 Scope.....	149
§ 192.703 General.....	149

§ 192.705	Transmission Lines: Patrolling.....	149
§ 192.706	Transmission Lines: Leakage Surveys	150
§ 192.707	Line Markers for Mains and Transmission Lines	150
§ 192.709	Transmission Lines: Record-Keeping	151
§ 192.710	Transmission lines: Assessments outside of high consequence areas	151
§ 192.711	Transmission Lines: General Requirements for Repair Procedures.....	151
§ 192.712	Analysis of predicted failure pressure	151
§ 192.713	Transmission Lines: Permanent Field Repair of Imperfections and Damages	156
§ 192.715	Transmission Lines: Permanent Field Repair of Welds	156
§ 192.717	Transmission Lines: Permanent Field Repair of Leaks	157
§ 192.719	Transmission Lines: Testing of Repairs	157
§192.720	Distribution Systems: Leak Repair	157
§ 192.721	Distribution Systems: Patrolling	157
§ 192.723	Distribution Systems: Leakage Surveys and Procedures	158
§ 192.724	Hazardous Facilities.....	160
§ 192.725	Test Requirements for Reinstating Service Lines	160
§ 192.727	Abandonment or Deactivation of Facilities.....	160
§ 192.731	Compressor Stations: Inspection and Testing of Relief Devices.....	161
§ 192.735	Compressor Stations: Storage of Combustible Materials	161
§ 192.736	Compressor Stations: Gas Detection	161
§ 192.739	Pressure Limiting and Regulating Stations: Inspection and Testing	162
§ 192.740	Pressure regulating, limiting, and overpressure protection--Individual service lines directly connected to regulated gathering or transmission pipelines	163
§ 192.741	Pressure Limiting and Regulating Stations: Telemetry or Recording Gauges	163
§ 192.743	Pressure Limiting and Regulating Stations: Capacity of Relief Devices	164
§ 192.745	Valve Maintenance: Transmission Lines.....	164
§ 192.747	Valve Maintenance: Distribution Systems.....	164
§ 192.749	Vault Maintenance	164
§ 192.750	Launcher and receiver safety	165
§ 192.751	Prevention of Accidental Ignition.....	165
§ 192.753	Caulked Bell and Spigot Joints	165
§ 192.755	Protecting Cast Iron Pipelines.....	165
§192.756	Joining plastic pipe by heat fusion; equipment maintenance and calibration	166
SUBPART N -	Qualification of Pipeline Personnel	166
§ 192.801	Scope.....	166
§ 192.803	Definitions	166
§ 192.805	Qualification Program	167
§ 192.807	Recordkeeping.....	167

§ 192.809 General	167
SUBPART O GAS TRANSMISSION PIPELINE INTEGRITY MANAGEMENT	168
§ 192.901 What do the regulations in this subpart cover?	168
§ 192.903 What definitions apply to this subpart?	168
§ 192.905 How does an operator identify a high consequence area?.....	170
§ 192.907 What must an operator do to implement this subpart?	170
§ 192.909 How can an operator change its integrity management program?	171
§ 192.911 What are the elements of an integrity management program?	171
§ 192.913 When may an operator deviate its program from certain requirements of this subpart?	172
§ 192.915 What knowledge and training must personnel have to carry out an integrity management program?.....	173
§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?	173
§ 192.919 What must be in the baseline assessment plan?	175
§ 192.921 How is the baseline assessment to be conducted?	176
§ 192.923 How is direct assessment used and for what threats?	177
§ 192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?	178
§ 192.927 What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?	179
§ 192.929 What are the requirements for using Direct Assessment for Stress Corrosion Cracking (SCCDA)?	181
§ 192.931 How may Confirmatory Direct Assessment (CDA) be used?	182
§ 192.933 What actions must be taken to address integrity issues?	182
§ 192.935 What additional preventive and mitigative measures must an operator take?.....	184
§ 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?	185
§ 192.939 What are the required reassessment intervals?	187
§ 192.941 What is a low stress reassessment?	189
§ 192.943 When can an operator deviate from these reassessment intervals?.....	190
§ 192.945 What methods must an operator use to measure program effectiveness?.....	190
§ 192.947 What records must an operator keep?.....	190
§ 192.949 [Removed and Reserved]	191
§ 192.951 Where does an operator file a report?	191
SUBPART P GAS DISTRIBUTION PIPELINE INTEGRITY MANAGEMENT (IM).....	191
§ 192.1001 What definitions apply to this subpart?.....	191
§ 192.1003 What do the regulations in this subpart cover?.....	192
§ 192.1005 What must a gas distribution operator (other than a small LPG operator) do to implement this subpart?	192

§ 192.1007 What are the required elements of an integrity management plan?.....	192
§ 192.1009 [Removed and Reserved]	194
§ 192.1011 What records must an operator keep?	194
§ 192.1013 When may an operator deviate from required periodic inspections under this part?	194
§ 192.1015 What must a small LPG operator do to implement this subpart?	194
APPENDIX A TO PART 192 – RESERVED	196
APPENDIX B TO PART 192 - QUALIFICATION OF PIPE AND COMPONENTS	197
I. Listed Pipe Specifications	197
II. Steel Pipe of Unknown or Unlisted Specification	198
III. Steel Pipe Manufactured Before November 12, 1970, to Earlier Editions of Listed Specifications	199
APPENDIX C TO PART 192 - QUALIFICATION OF WELDERS FOR LOW STRESS LEVEL PIPE	200
I. Basic Test	200
II. Additional Tests for Welders of Service Line Connections to Mains	200
III. Periodic Tests for Welders of Small Service Lines	200
APPENDIX D TO PART 192 - CRITERIA FOR CATHODIC PROTECTION AND DETERMINATION OF MEASUREMENTS	201
I. Criteria for Cathodic Protection	201
II. Interpretation of Voltage Measurement	202
III. Determination of Polarization Voltage Shift	202
IV. Reference Half Cells	202
APPENDIX E TO PART 192 - GUIDANCE ON DETERMINING HIGH CONSEQUENCE AREAS AND ON CARRYING OUT REQUIREMENTS IN THE INTEGRITY MANAGEMENT RULE	203
I. Guidance on Determining a High Consequence Area	203
II. Guidance on Assessment Methods and Additional Preventive and Mitigative Measures for Transmission Pipelines	203
APPENDIX F TO PART 192 - Criteria for Conducting Integrity Assessments Using Guided Wave Ultrasonic Testing (GWUT)	207
PART 199 - DRUG AND ALCOHOL TESTING	234
SUBPART A - GENERAL	234
§ 199.1 Scope	234
§ 199.2 Applicability	234
§ 199.3 Definitions	235
§ 199.5 DOT Procedures	235
§ 199.7 Stand-down Waivers	236
§ 199.9 Preemption of State and Local Laws	236
SUBPART B – DRUG TESTING	236

§ 199.100 Purpose	236
§ 199.101 Anti-Drug Plan.....	236
§ 199.103 Use of Persons Who Fail or Refuse a Drug Test	237
§ 199.105 Drug Tests Required	237
§ 199.107 Drug Testing Laboratory	239
§ 199.109 Review of Drug Testing Results	239
§ 199.111 [Removed and Reserved].....	240
§ 199.113 Employee Assistance Program.....	240
§ 199.115 Contractor Employees.....	240
§ 199.117 Record Keeping.....	240
§ 199.119 Reporting of Anti-Drug Testing Results	241
SUBPART C – ALCOHOL MISUSE PREVENTION PROGRAM	242
§ 199.200 Purpose	242
§ 199.201 [Reserved]	242
§ 199.202 Alcohol Misuse Plan	242
§§ 199.203-199.205 [Reserved].....	242
§ 199.209 Other Requirements Imposed by Operators	242
§ 199.211 Requirements for Notice	242
§ 199.213 [Reserved]	242
§ 199.215 Alcohol Concentration	243
§ 199.217 On-duty Use	243
§ 199.219 Pre-duty Use	243
§ 199.221 Use Following an Accident.....	243
§ 199.223 Refusal to Submit to a Required Alcohol Test	243
§ 199.225 Alcohol Tests Required	243
§ 199.227 Retention of Records.....	245
§ 199.229 Reporting of Alcohol Testing Results	246
§ 199.231 Access to Facilities and Records	247
§ 199.233 Removal from Covered Function	247
§ 199.235 Required Evaluation and Testing.....	248
§ 199.237 Other Alcohol-related Conduct	248
§ 199.239 Operator Obligation to Promulgate a Policy on the Misuse of Alcohol.....	248
§ 199.241 Training for Supervisors.....	249
§ 199.243 Referral, Evaluation, and Treatment	249
§ 199.245 Contractor Employees.....	250

PREFACE

ARKANSAS GAS PIPELINE CODE

On August 12, 1968, the United States Congress passed Public Law 90-481, better known as the Natural Gas Pipeline Safety Act of 1968. This Act authorizes the Secretary of Transportation to administer this law, and to develop standards and regulate the enforcement of such standards for the design, installation, inspection, testing, construction, extension, operation, replacement and maintenance of pipeline facilities. Enacted on July 5, 1994, Public Law 103-272 revised, codified, and enacted the provisions of the Act without substantive change as Chapter 601 of Title 49, United States Code. Title 49 U.S.C. 60105 authorizes a state to regulate these minimum standards under a certification to the Secretary of Transportation that provides certain provisions are met by the state.

On March 15, 1971, the Arkansas General Assembly enacted Act 285 of 1971, the Arkansas Natural Gas Pipeline Safety Act of 1971, codified as Ark. Code Ann. § 23-15-201 *et seq.* Act 285 authorized the Arkansas Public Service Commission to administer a state program pertaining to the design, installation, inspection, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities used to transport natural gas. The Pipeline Safety Office was established and tasked with the responsibility of developing and implementing this program. Act 285 is far-reaching and affects directly or indirectly persons who distribute or use natural gas.

As long as natural gas flows through a closed controlled system, it remains an efficient, inexpensive and safe servant. However, when it escapes from its pipes, gas can turn on man violently and quickly. In passing the Arkansas Natural Gas Pipeline Safety Act of 1971, the Arkansas General Assembly intended to provide laws and standards which assured that these systems would continue to be operated in a safe manner and thereby reduce the possibility of gas escaping from its closed system. The objective of the pipeline safety program within Arkansas is to keep the gas confined to a closed, controlled system. This is best accomplished by requiring gas companies, operators of gas systems, and all persons who install natural gas pipelines to install and maintain them using only authorized materials and procedures and to comply with standards designed to ensure continuing quality of operation and maintenance.

The procedures and standards adopted by the Arkansas Public Service Commission, as authorized by Act 285, are known as the Arkansas Gas Pipeline Code. Compliance with the Code is mandatory under state law and non-compliance by any person engaging in the transportation of gas or who owns or operates pipeline facilities is punishable by a civil penalty not to exceed \$200,000 per violation for each day the violation continues, except that the maximum civil penalty may not exceed \$2,000,000 for any related series of violations. The law also provides authority for the Commission to file suit to restrain violations of the Code, including the restraint of transportation of gas or the operation of a pipeline facility.

The Arkansas Gas Pipeline Code is comprised of Parts 190, Enforcement Procedures; 191, Annual and Incident Reports; 192, Minimum Safety Standards; and 199, Drug and Alcohol Testing. The paragraphs in Parts 191, 192, and 199 correspond to the paragraph numbers of Parts 191, 192, and 199 of Title 49, Code of Federal Regulations, Pipeline Safety Regulations.

ADMINISTRATIVE HISTORY
of the
ARKANSAS GAS PIPELINE CODE

Docket	Effective Date	Order No.	Subject Matter of Docket/Order
U-2424 (72-024-U)	01/03/1973	---	Adoption of Arkansas Gas Pipeline Code
U-2683 (75-082-U)	01/30/1976	---	General Revisions to Code.
U-2794 76-109-U)	02/24/1977	---	General Revisions to Code.
U-2908 (77-008-U)	02/03/1978	---	General Revisions to Code.
U-2999 (78-055-U)	02/15/1979	---	General revision to Code with emphasis on corrosion requirements.
U-3083 (80-007-U)	03/18/1980	2	Adds requirements for qualifying persons and procedures for the joining of plastic pipe.
81-040-U	03/11/1081	3	Amends requirements concerning plastic pipe joining and external corrosion control monitoring.
82-059-R	04/16/1982	6	Adds Part 190 – Pipeline Safety Procedures, and updates industry standards publications.
83-015-R	03/07/1983	2	Adds requirements for a Damage Prevention Program and provides flexibility in scheduling inspections and tests.
84-034-R	07/06/1984	4	General Code revisions.
85-086-R	08/21/1985	3	Revised Part 191 - Transportation of Natural and Other Gas by Pipeline: Annual Reports and Incident Reports. Also revised the Code format. Complete republication by Order No. 4.
86-169-R	12/15/1986	3	Revised definition of operator. Amends provision regarding plastic pipe, welder qualification, preheating, and stress relieving.
88-005-R	07/14/1988	4	Revised Part 190 to provide for waivers, response to accident recommendations, and numbered paragraphs. Part 192 amended for locations, MAOP, testing repairs, odorization damage prevention, and R/V calculation.
89-034-R	08/02/1989	3	Part 191 amended to include Safety-Related Condition Reports. Part 192 amended for deletion references, adding requirements for safety conditions to be included in O&M plans, and requirements for tie-in joints.
	08/22/1989	5	Added Part 199 – Drug Testing. Establishes employee drug testing program required of operators subject to Part 192.
90-015-R	03/23/1990	3	General revisions with emphasis on updating of Standards & Specifications; class location vs. MAOP; cast/ductile iron, and copper pipe; Part 199 - changes caused by deletion of "Rehabilitation Committee" and its

			definition; and changes in Drug tests required.
91-056-R	06/06/1991	3	Care when using tracer wire with plastic pipe, and lubrication requirements for valves.
92-036-R	05/12/1992	3	Parts 192 and 199 changed to reflect requirement of operators to amend plans and procedures as necessary for safety. Preface and Part 190 changed to reflect increase in civil penalties.
93-020-R	04/26/1993	3	Parts 191 and 192 changed to include gathering lines containing 100 ppm or more of hydrogen sulfide. Part 192 further changed by correcting certain discrepancies not previously discovered. Code format revised and complete republication of the Arkansas Gas Pipeline Code.
94-025-R	09-12-1994	4	Update of referenced Standards, addition of requirement for gas detection in compressor station buildings, and clarification of leakage survey requirements. Part 199 changes keeping and a new requirement for a report on the anti-drug program.
95-116-R	04/27/1995	3	Definitions section and Parts 190 and 192 changed reflect the requirement that certain new and replacement pipelines be designed and constructed to accommodate instrumented internal inspection devices. Part 190 changed to clarify the language in the issuance and handling of show cause orders. Part 192 changed to require meters which have been installed indoors to be in a ventilated place and not less than 3 feet from any source of ignition or source of heat which might damage the meter, to require detailed procedures in O&M manuals, that operators review and update their O&M manuals each year, and that operators prepare and follow procedures to safeguard personnel from unsafe accumulations of vapors or gas in excavated trenches. Part 199 reformatted to add Subpart B, Alcohol Misuse Prevention Program. Preface changed to include new title of Part 199. Complete republication of the Arkansas Gas Pipeline Code.
96-181-R	08/20/1996	3	Preface and Part 190 changed to reflect civil penalties. Part 192 changed to include notification requirement for customer-owned service lines, to extend existing excavation damage prevention requirements for gas pipelines in urban areas to gas pipelines in rural areas, and to require, with limited exceptions, line markers for transmission lines in urban areas. Part 199 changed to allow for the possibility of a reduced random drug testing rate, and to require reporting of information concerning missed tests. Complete republication of the Arkansas Gas Pipeline Code.
97-034-R	04/03/1997	3	Preface changed to explain the codification of Natural Gas Pipeline Safety Act. Definition of "petroleum gas"

			added and definition of "transmission line" revised in the Definitions section. Numerous minor changes to Parts 191 and 192. Addition of performance standards for excess flow valves to Part 192. Appendices A and B to Part 192 updated. Minor revisions to Part 199. Complete republication of the Arkansas Gas Pipeline Code.
99-130-R	08/02/1999	3	All Parts changed to include metric equivalents for English measures. Part 192 changed to require Excess Flow Valves ("EFO") close at 50% or of the manufacturer's rated closure flow rate operating at 10 pounds per square inch ("p.s.i.g."); removed the requirement to installation of EFO's beneath hard surfaces; operators to notify customers of the option to install EFO's before the installation or replacement of service lines; require that all operators must participate in a qualified one-call system; added transmission or distribution of gas containing H2S to reflect the exact language in Arkansas Code Annotated 23-15-203 (3); removed atmospheric corrosion requirements for offshore facilities. Appendix A revised to incorporate certain versions of The American Society for Testing and Materials Standards by reference. Part 199 revised to clarify terms; added requirements for a Substance Abuse Professional ("SAP"). Complete republication of the Arkansas Gas Pipeline Code.
00-312-R	12/11/2000	4	Part 190.15 revised to include falsification paperwork as probable violation. Part 192.17 revised to allow the use of a certified letter for notification of probable violation. New Subpart N - Operator Qualification added. Minor changes to Subpart I and M. Complete republication of the Arkansas Gas Pipeline Code.
04-088-R	08/26/2004	3	Adopted Federal Office of Pipeline Safety Amendments 192-86A, 192-89, 192-89A, 192-93, 192-95, 199-19 and 199-21.
06-123-R	12/07/2006	3	Adopted Federal Pipeline and Hazardous Material Safety Administration Amendments 192-96, 192-97, 192-98, 192-99, 192-100, 192-102, 192-103, 199-20, 49 CFR Part 193 in entirety, Amendment 193-19, Nomenclature amendment regarding the change of the Research Special Programs Administration into the Pipeline and Hazardous Materials Safety Administration Act, the 82 nd General Assembly of the Arkansas Legislature, and Act 153 of the 83 rd General Assembly of the Arkansas Legislature. Complete republication of the Arkansas Gas Pipeline Code.
08-167-R	05/04/2009	3	Adopted Federal Pipeline and Hazardous Safety

			Administration amendment 192-103A, update of regulatory references to technical standards, amendment regarding design and construction standards to reduce internal corrosion in gas transmission pipelines, 192-104 Integrity Management Program modifications and clarifications, amendment regarding applicability of public awareness regulation to certain gas distribution operators, and amendment regarding administrative procedures, address updates, and technical amendments. Complete republication of the Arkansas Gas Pipeline Code.
11-166-R	06/08/2012	5	Adopted Federal Pipeline and Hazardous Material Safety Administration (“PHMSA”) 108, 109, 110, 111, 112, 114, and 115 to Part Adopted PHMSA amendments 22 and 23 to Part Adopted PHMSA amendment 21 to Part Complete republication of the Arkansas Gas Code.
13-027-R	10/16/2013	3	Editorial changes, adopted Private Line definition, added 192.27 Status of Leaks requirement, and added 192.724 Hazardous Facilities requirement.
14-029-R	09/25/2014	5	Adopted Federal Pipeline and Hazardous Material Safety Administration amendment to incorporate higher civil penalties and minor redesignation changes. Also incorporated changes from Act 1343 of 2013 from the Arkansas General Assembly. Complete republication of the Arkansas Gas Pipeline Code.
16-093-R	05/19/2017	4	Adopted 2015 Federal Pipeline and Hazardous Material Safety Administration amendments 191-23, 192-119, 192-120, 193-25, and 199-26 (80 FR 168, 12762, and 46847-01); and made technical corrections. Complete republication of the Arkansas Gas Pipeline Code.
19-069-R	03/31/2020	4	Adoption of 2016 and 2017 Federal Pipeline and Hazardous Material Safety Administration amendments 190-19 and 192-121 (81 FR 72739 and 82 FR 7972) and made technical corrections. Complete republication of the Arkansas Gas Pipeline Code.
22-020-R	8/18/2022	3	Adoption of 2019, 2020, 2021, and 2022 Federal Pipeline and Hazardous Material Safety Administration amendments 192-124, 191-26, 192-125, 192-127, 191-29, 192-128, (83 FR 58694, 84 FR 16770, 84 FR 52180, 85 FR 40132, 86 FR 2210, and 86 FR 12835.

DEFINITIONS

DEFINITIONS OF WORDS/PHRASES USED IN THE ARKANSAS GAS PIPELINE CODE

Except as otherwise provided in this Code:

Abandoned means permanently removed from service.

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

Administrator means the Administrator of the Pipeline and Hazardous Materials Safety Administration or any person to whom authority in the matter concerned has been delegated by the U.S. Secretary of Transportation.

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

Business District means a location where gas mains are utilized to serve customers that are predominately commercial in nature, and where the street and/or sidewalk paving generally extends from the centerline of a thoroughfare to the established building line on either side.

Change to a segment of pipeline means a physical change in the pipeline or significant changes in operating pressure.

Commission means, unless the context otherwise requires, the Arkansas Public Service Commission or any person or entity to whom the Commission has delegated authority in the matter concerned.

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

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

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

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

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

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

Emergency Order means a written order issued in response to an imminent hazard imposing restrictions, prohibitions, or safety measures on owners and operators of gas or hazardous liquid pipeline facilities, without prior notice or an opportunity for hearing.

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

Gathering Line means a pipeline that transports gas from a current production facility to a

transmission line or main.

High Pressure Distribution System means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer.

Imminent Hazard means the existence of a condition relating to a gas or hazardous liquid pipeline facility that presents a substantial likelihood that death, serious illness, severe personal injury, or a substantial endangerment to health, property, or the environment may occur before the reasonable foreseeable completion date of a formal proceeding begun to lessen the risk of such death, illness, injury, or endangerment.

Incident means any of the following events:

- (1) An event that involves a release of gas from a pipeline, gas from an underground natural gas storage facility, , and that results in one or more of the following consequences:
 - (i) A death, or personal injury necessitating in-patient hospitalization;
 - (ii) Estimated property damage of \$122,000 or more, including loss to the operator and others, or both, but excluding the cost of gas lost; For adjustments for inflation observed in calendar year 2021 onwards, changes to the reporting threshold will be posted on PHMSA's website. These changes will be determined in accordance with the procedures in Appendix A to part 191; or
 - (iii) Unintentional estimated gas loss of three million cubic feet or more.
- (2) An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraph (1) or (2) of this definition.

Key Valves means shut off valves in a distribution system or transmission line which may be necessary to isolate segments of a system or line for emergency purposes.

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

Listed Specification means a specification listed in Section I of Appendix B to Part 192.

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

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

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

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

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

Mobile Home Park means two or more mobile homes located on a contiguous tract of land.

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

Manual service line shut-off valve means a curb valve or other manually operated valve located near the service line that is safely accessible to operator personnel or other personnel authorized by the operator to manually shut off gas flow to the service line, if needed.

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

Operator means a person who:

- (1) Engages in the transportation of gas; or
- (2) Operates a distribution system within a mobile home park, public housing authority, or multiple building complex if:
 - (A) The system:
 - (i) Is not owned, nor the responsibility of a public or municipal utility; and
 - (ii) Is used to transport gas from a master meter or a public/municipal utility main to consumers who may or may not be metered; and
 - (B) The gas distributed is not consumed solely by the owner/operator.

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

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 p.s.i.g. (1434 kPa) gage at 100°F (38°C).

Petroleum Refinery means an industrial or manufacturing facility or plant primarily engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants or other products through the processing of petroleum crude oil that is subject to:

- (A) The federal Environmental Protection Agency Standards of Performance for New Stationary Sources set forth in Subpart GGG of 40 CFR Part 60 or successor regulations;
- (B) The federal *Environmental* Protection Agency Chemical Accident Prevention Provisions set forth in Subparts, A, B, D, E, F, G, and H of 40 CFR Part 68 or successor *regulations*; and
- (C) The federal Occupational Safety and Health Administration Regulations governing process safety management of highly hazardous chemicals set forth in 29 CFR §1910.119 or successor regulations.

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

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

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

Pipeline Facilities includes without limitation, new and existing pipe, pipe rights-of-way, and any equipment, facility or building used in the transportation of gas or the treatment of gas during the course of transportation of gas.

Pipeline Safety Office or PSO means the Pipeline Safety Office within the Arkansas Public Service Commission that administers the Arkansas Natural Gas Pipeline Safety Act of 1971, Arkansas Code § 23-15-201 *et seq.*, the Arkansas Gas Pipeline Code, and related laws, rules, and regulations.

Production Facilities includes without limitation, piping or equipment used in the production, extraction, recovery, lifting, stabilization, separation or treatment of natural gas or associated storage or measurement from the wellhead to a meter where the gas is transferred to a custodian other than the well operator for gathering or transport, commonly known as a “custodial transfer meter.”

Production Process means the extraction of gas from the geological source of supply to the surface of the earth, thence through the lines and equipment used to treat, compress and measure the gas between the wellhead and the meter where it is either sold or delivered to a custodian other than the well operator for gathering and transport to a place of sale, sometimes called a “custodial transfer meter.”

Service Line means a distribution line that transports gas from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer’s piping, whichever is further downstream, or at the connection to customer piping if there is no meter.

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

SMYS means specified minimum yield strength, and is:

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

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.

Test Failure means a break or rupture that occurs during strength proof testing of transmission or gathering lines that are of such magnitude as to require repair before continuation of the test.

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

- (1) Transports gas from a gathering line or storage facility to a gas distribution center, storage facility, or large volume customer that is not down-stream from a gas distribution center;
- (2) Operates at a hoop stress of 20 percent or more SMYS; or

(3) Transports gas within a storage field.

NOTE: A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

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

PART 190-PIPELINE SAFETY ENFORCEMENT PROCEDURES

SUBPART A - GENERAL

§ 190.1 Purpose

This part prescribes procedures utilized by the Arkansas Public Service Commission (Commission) in carrying out its responsibilities regarding pipeline safety under the Arkansas Natural Gas Pipeline Safety Act of 1971 (Act 285 of 1971, as amended; Ark. Code Ann. § 23-15-201 et seq.). Any conflict between the Commission's Rules and Regulations and the Arkansas Statutes shall be resolved in favor of the statutes.

§ 190.3 Service

Each show cause order issued under this part shall be served in accordance with the current provisions of the Commission's Rules of Practice and Procedure and Ark. Code Ann. §23-2-405.

§ 190.5 Subpoenas; Witness Fees

The issuance of subpoenas and payment of witness fees shall be in accordance with the current provisions of the Commission's Rules of Practice and Procedure and Ark. Code Ann. §23-2-402 and § 23-2-414.

§ 190.7 Extension of Time

In those instances when the actions necessary to correct documented deficiencies will exceed the time limit given in the notice of probable violation, an operator may request an extension of time in order to effect compliance. Each request must detail the reason(s) why compliance cannot be accomplished by the original suspense date, and the date the operator believes the necessary compliance actions can be completed. If the Commission finds the request to be reasonable a new suspense date may be established.

§ 190.9 Petitions for Finding or Approval

- (a) In circumstances where a rule contained in Part 192 authorizes the Administrator of the Pipeline and Hazardous Materials Safety Administration of the United States Department of Transportation to make a finding or approval, an operator may petition the Administrator for such a finding or approval.
- (b)
 - (1) Each petition must refer to the rule authorizing the action sought and contain information or arguments that justify the action. Unless otherwise specified, no public proceeding is held on a petition before it is granted or denied. After a petition is received, the Administrator or participating state agency notifies the petitioner of the disposition of the petition or, if the request requires more extensive consideration or additional information or comments are requested and delay is expected, of the date by which action will be taken.
 - (2) For operators seeking a finding or approval involving intrastate pipeline transportation, petitions must be sent to: Pipeline Safety Office, Arkansas Public Service Commission, P.O. Box 400, Little Rock, Arkansas 72203-0400.
 - (3) For operators seeking a finding or approval involving interstate pipeline transportation, petitions must be sent to the Administrator, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue, SE, Washington, DC 20590.
- (c) All petitions must be received at least 90 days prior to the date by which the operator requests the finding or approval to be made.

- (d) The Administrator will make all findings or approvals of petitions initiated under this section. The Pipeline Safety Office (PSO), upon receiving petitions initiated under this paragraph, shall provide the Administrator a written recommendation by certified mail, return receipt requested as to the disposition of any petition received by the PSO. If the Administrator does not reverse or modify a recommendation made by the PSO within 10 business days of its receipt, the recommended disposition shall constitute the Administrator's decision on the petition.

§ 190.11 Waivers

If unusual difficulty results from implementing a safety standard in Part 192, application may be made to the Commission for exemption from a particular standard. The application for exemption shall be accompanied by a thorough justification for requested actions.

SUBPART B - ENFORCEMENT

§ 190.15 Inspections, Production of Records, and Accident Investigations

- (a) The Commission may conduct inspections and investigate accidents in accordance with Ark. Code Ann. §23-15-207. Operators are required to provide records requested by the Commission pursuant to Ark. Code Ann. §23-15-206 for any inspection or accident investigation.
- (b) If an inspection or accident investigation indicates that a probable violation exists, or if an operator falsifies records, or fails to provide any record(s) requested by the Commission, a notice of probable violation will be sent to the operator. For the purposes of this rule, a probable violation for failing to provide records shall arise only from failure to provide records required by § 190.15 (a) in the form in which they are maintained in the ordinary course of business. The operator shall be allowed the time prescribed by the Commission's Rules of Practice and Procedure to respond after service of any such request for records. For purposes of this rule, falsifying records shall mean "the original entry or subsequent modification of any official record with the intent to mislead or deceive a third party later examining the document."
- (c) If an accident investigation results in the PSO making recommendations in a formal accident investigation report, the operator will make written response to those recommendations within the time frame specified in the report.

§ 190.17 Notice of Probable Violation

- (a) The Commission begins enforcement proceedings by serving a notice of probable violation of the Arkansas Gas Pipeline Code or any order issued thereunder. This notification shall advise the operator that a written response is required and that failure to respond may result in enforcement action in accordance with § 190.19.
- (b) A notice of probable violation issued under this section shall include:
 - (1) Statement of the provisions of the laws, regulations or orders which the respondent is alleged to have violated and a statement of the evidence upon which the allegations are based;
 - (2) Notice of response options available to the respondent.
- (c) The notice of probable violation shall normally be in the form of an inspection report mailed to the person charged. However, the notice of probable violation may be served in the form of a certified letter or show cause order.

- (d) A notice of probable violation for failure to produce or falsification of records may be served in the form of a certified letter or show cause order. Falsification of records may also be referred to the Inspector General of the U.S. Department of Transportation for investigation and prosecution under applicable provisions of federal criminal law.

§ 190.19 Show Cause Orders

The Commission may issue a show cause order notifying the owner or operator of a probable violation and advising the person to correct it or be subject to enforcement action. The severity of the probable violation shall be the determining factor in the type of notice issued by the Commission. A show cause order shall be served as provided in § 190.3.

§ 190.21 Response Options

An operator has 20 calendar days from the date of receipt of a show cause order to respond. The operator may:

- (a) Submit written response to the allegations. The written response may contain one of the following:
 - (1) Evidence to rebut the allegations of the show cause order; or
 - (2) Actions taken to achieve compliance; or
 - (3) A request for an extension of time to correct the alleged probable violation(s).
- (b) Request a hearing.
 - (1) A request for a hearing shall be in writing and shall conform to the Commission's Rules of Practice and Procedure.

Failure of the operator to respond in a timely manner to a show cause order under either subsection (a) or (b) of this section shall constitute a waiver of the operator's right to contest the allegations. The Commission may then act on the basis of the case file compiled by the Staff.

§ 190.23 Case File

The Case File compiled by the Staff after the issuance of a show cause order shall contain the following information:

- (a) The inspection reports and any other evidence of alleged violations;
- (b) A copy of the show cause order;
- (c) Any material submitted by the operator pursuant to § 190.21(a); and
- (d) The evaluation of the Staff and their recommendations for final action.

§ 190.25 Final Order

The Commission shall issue a final order at the conclusion of any proceedings initiated by a show cause order. The final order shall include:

- (a) Findings of fact addressing all material issues and conclusions of law;
- (b) A statement of the amount of the civil penalty, if any, and the procedures for the payment of the penalty; and
- (c) A statement of the necessary actions to be taken by the operator and a schedule for completion of those actions, if any are found to be necessary.

§ 190.27 Petitions for Reconsideration

Subsequent to a final order, the operator may request a rehearing pursuant to Ark. Code Ann. § 23-2-422, and the Commission's Rules of Practice and Procedure.

§ 190.29 Civil Penalties

The Commission may assess civil penalties prescribed by Ark. Code Ann. § 23-15-211 for violations of the Arkansas Gas Pipeline Code which as of July 1, 2016, shall not exceed two hundred thousand dollars (\$200,000) for each violation for each day that the violation persists, except that the maximum civil penalty shall not exceed two million dollars (\$2,000,000) for any related series of violations. Before assessing a civil penalty, the Commission shall follow the procedures established by §§ 190.19 and 190.25.

§ 190.31 Payment of Civil Penalties

Any civil penalty not promptly paid to the Commission shall be recovered with interest thereon from the date of the order in a civil action brought by the Commission under Ark. Code Ann. §§ 23-15-211 - 23-15-212.

SUBPART C - SPECIFIC RELIEF

§ 190.41 Hazardous Conditions

- (a) Whenever the Commission finds a particular facility to be hazardous to life or property, it shall be empowered to require the person operating such facility to take such corrective measures necessary to remove such hazards.
- (b) Where the operator contests the corrective measures imposed by the Commission, the operator may request a hearing which shall be made in writing and shall conform to the Commission's Rules of Practice and Procedure. A request for a hearing under this paragraph shall not act to stay the corrective measures initially required by the Commission.

§ 190.43 Injunctive Action

The Commission may restrain violations of the Arkansas Natural Gas Pipeline Safety Act of 1971, as amended, by seeking injunctive relief pursuant to Arkansas Code Ann. §23-15-212.

PART 191 - TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE:

ANNUAL REPORTS, INCIDENT REPORTS, AND SAFETY-RELATED CONDITION REPORTS

§ 191.1 Scope

- (a) This part prescribes requirements for the reporting of incidents, safety-related conditions, and annual pipeline summary data, National Registry of Operators information, and other miscellaneous conditions by operators of underground natural gas storage facilities and natural gas pipeline facilities located in the United States or Puerto Rico.
- (b) Sections 191.22(b) and (c) and 191.23 do not apply to the onshore gathering of gas –
 - (1) Through a pipeline that operates at less than 0 psig (0kPa); or
 - (2) Through a pipeline that is not a regulated onshore gathering pipeline.

§ 191.5 Immediate Notice of Certain Incidents

- (a) At the earliest practicable moment following discovery, but no later than one hour after confirmed discovery, each operator must give notice in accordance with paragraph (b) and (d) of this section of each incident as defined in the Definitions Section.

Incidents reportable under this subsection (a) 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) Within 48 hours after the confirmed discovery of an incident, to the extent practicable, an operator must revise or confirm its initial telephonic notice required in paragraph (b) of this section with an estimate of the amount of product released, an estimate of the number of fatalities and injuries, and all other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages. If there are no changes or revisions to the initial report, the operator must confirm the estimates in its initial report.
- (d) In addition to the telephonic notice required in paragraph (b) of this section, notice must also be made by telephone to (501) 682-5716 and electronically via email to

PIR.MailBox@arkansas.gov and include the information listed in paragraph (b). Reports will be made to PSO personnel in accordance with instructions issued by the PSO.

§ 191.7 Report Submission Requirements

- (a) Each written report required by this part, with the exception of the "Safety-Related Condition Report", will be made to Pipeline Safety Office, Arkansas Public Service Commission, P. O. Box 400, Little Rock, Arkansas 72203-0400. These will be submitted in duplicate.
- (b) The Safety-Related Condition Reports required by §§ 191.23 and 191.25 will be submitted directly to: Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U. S. Department of Transportation, the Information Resources Manager, PHP-10, 1200 New Jersey Avenue, SE, Washington, DC 20590-0001. A copy of these reports must be submitted concurrently to the Pipeline Safety Office, Arkansas Public Service Commission.
- (c) *General.* Except as provided in paragraph (d) of this section, an operator must submit each report required by this part electronically to the Pipeline and Hazardous Materials Safety Administration at <http://portal.phmsa.dot.gov/pipeline> unless an alternative reporting method is authorized in accordance with paragraph (f) of this section.
- (d) *Exceptions.* An operator is not required to submit a safety-related condition report (§ 191.25) electronically.
- (e) *Safety Related Conditions.* An operator must submit concurrently to the Arkansas Pipeline Safety Office and to PHMSA a safety-related condition report required by §191.23 for intrastate pipeline transportation.
- (f) *Alternative Reporting Method.* If electronic reporting imposes an undue burden and hardship, an operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, PHP-20, 1200 New Jersey Avenue, SE, Washington, DC 20590. The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202-366-8075, or electronically to informationresourcesmanager@dot.gov or make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received.
- (g) *National Pipeline Mapping System (NPMS).* An operator must provide the NPMS data to the address identified in the NPMS Operator Standards manual available at www.npms.phams.dot.gov or by contacting the PHMSA Geographic Information Systems Manager at (202) 366-4595.

§ 191.9 Distribution System: Incident Report

- (a) Each operator of a distribution pipeline system shall submit Department of Transportation Form PHMSA F7100.1 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).
- (a) 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.
- (b) Master meter operators are not required to submit an incident report as required by this section.

§ 191.11 Distribution System: Annual Report

- (a) Except as provided in paragraph (b) of this section, each operator of a distribution system shall submit an annual report for that system on Department of Transportation Form PHMSA F7100.1-1. This report shall be submitted for the preceding calendar year via email to APSC.PSORReports@arkansas.gov. The report must be received no later than March 15 of each year.
- (b) *Not* required. The annual report requirement in this section does not apply to a master meter system, a petroleum gas system that serves fewer than 100 customers from a single source, or an individual service line directly connected to a production pipeline or a gathering line other than a regulated gathering line as determined in § 192.8.

§ 191.12 [Removed and Reserved]

§ 191.13 Distribution Systems Reporting Transmission Pipelines: Transmission or Gathering Systems Reporting Distribution Pipelines

Each operator, primarily engaged in gas distribution, who also operates gas transmission or gathering pipelines shall submit separate reports for these pipelines as required by §§ 191.15 and 191.17. Each operator, primarily engaged in gas transmission or gathering, who also operates gas distribution pipelines shall submit separate reports for these pipelines as required by §§ 191.9 and 191.11.

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

- (a) *Pipeline Systems –*
 - (1) *Transmission, Offshore Gathering, or Regulated Onshore Gathering.* Each operator of a transmission, offshore gathering, or a regulated onshore gathering pipeline system must submit Department of Transportation (DOT) Form PHMSA F7100.2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under § 191.5.
 - (2) *Reporting-regulated gathering.* Each operator of a reporting-regulated gathering pipeline system must submit DOT Form PHMSA F 7100.2-2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under § 191.5 that occurs after May 16, 2022.
- (b) *Underground natural gas storage facility.* Each operator of a UNGSF must submit DOT Form PHMSA F7100.2 as soon as practicable but not more than 30 days after the detection of an incident required to be reported under § 191.5.
- (c) *Supplemental Report.* When additional relevant information is obtained after the report is submitted under paragraph (a) or (b) of this section, the operator shall make supplementary reports as soon as practicable and as deemed necessary with a clear reference by date and subject to the original report.

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

- (a) *Pipeline Systems –*
 - (1) *Transmission, offshore gathering, or regulated onshore Gathering.* Each operator of a transmission system, offshore gathering, or a regulated onshore gathering pipeline system subject to the jurisdiction of the Commission shall submit an

annual report for that system on DOT Form PHMSA F 7100.2-1. This report shall be submitted for the preceding calendar year via email to APSC.PSORReports@arkansas.gov. The report must be received no later than March 15 of each year.

(2) *Type R gathering.* Beginning with an initial annual report submitted in March 2023 for the 2022 calendar year, each operator of a reporting-regulated gas gathering pipeline system must submit an annual report for that system on DOT Form PHMSA F 7100.2-3. This report shall be submitted for the preceding calendar year via email to APSC.PSORReports@arkansas.gov. The report must be received no later than March 15 of each year.

(b) Underground natural gas storage facility. Each operator of a UNGSF must submit an annual report on DOT form PHMSA 7100.4-1. This report shall be submitted for the preceding calendar year via email to APSC.PSORReports@arkansas.gov. The report must be received no later than March 15 of each year.

§ 191.21 OMB Control Number Assigned to Information Collection

This section displays the control number assigned by the Office of Management and Budget (OMB) to the information collection requirements in this part. The Paperwork Reduction Act requires agencies to display a current control number assigned by the Director of OMB for each agency information collection requirement.

OMB CONTROL NUMBER 2137-0522

Section of 49 CFR Part 191 where identified	Form No.
191.5	Telephonic and electronically via email.
191.9	PHMSA 7100.1, PHMSA 7100. 3.
191.11	PHMSA 7100.1-1, PHMSA 7100.3-1.
191.15	PHMSA 7100.2.
191.17	PHMSA 7100.2-1.
191.22	PHMSA 1000.1.

§ 191.22 National Registry of Pipeline and LNG operators

(a) *OPID Request.* Effective January 1, 2012, each operator of a gas pipeline, gas pipeline facility, must obtain from PHMSA an Operator Identification Number (OPID). An OPID is assigned to an operator for the pipeline or pipeline system for which the operator has primary responsibility. To obtain an OPID, an operator must complete an OPID Assignment Request DOT Form PHMSA F 1000.1 through the National Registry of Pipeline in accordance with § 191.7.

(b) *OPID validation.* An operator who has already been assigned one or more OPID by January 1, 2011, must validate the information associated with each OPID through the National Registry of Pipeline at <http://portal.phmsa.dot.gov/pipeline>, and correct that information as necessary, no later than June 30, 2012.

(c) *Changes.* Each operator of a gas pipeline, gas pipeline facility must notify PHMSA electronically through the National Registry of Pipeline at <http://portal.phmsa.dot.gov/pipeline> of certain events.

- (1) An operator must notify PHMSA of any of the following events not later than 60 days before the event occurs:
 - (i) Construction or any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe that costs \$10 million or more. If 60-day notice is not feasible because of an emergency, an operator must notify PHMSA as soon as practicable;
 - (ii) Construction of 10 or more miles of a new or replacement pipeline;
 - (iii) Construction of a new underground natural gas storage facility or the abandonment, drilling or well workover (including replacement of wellhead, tubing, or a new casing) of an injection, withdrawal, monitoring, or observation well for an underground natural gas storage facility.
 - (iv) Reversal of product flow direction when the reversal is expected to last more than 30 days. This notification is not required for pipeline systems already designed for bi- directional flow; or
 - (v) A pipeline converted for service under § 192.14 of this chapter, or a change in commodity as reported on the annual report as required by § 191.17.
- (2) An operator must notify PHMSA of any of the following events not later than 60 days after the event occurs:
 - (i) A change in the primary entity responsible (i.e., with an assigned OPID) for managing or administering a safety program required by this part covering pipeline facilities operated under multiple OPIDs.
 - (ii) A change in the name of the operator;
 - (iii) A change in the entity (e.g., company, municipality) responsible for an existing pipeline, pipeline segment, or pipeline facility; or
 - (iv) The acquisition or divestiture of 50 or more miles of a pipeline or pipeline system subject to Part 192 of this subchapter.
- (d) *Reporting.* An operator must use the OPID issued by PHMSA for all reporting requirements covered under this subchapter and for submissions to the National Pipeline Mapping System.

§ 191.23 Reporting Safety-Related Conditions

- (a) Except as provided in paragraph (b) of this section, each operator shall report in accordance with § 191.25 the existence of any of the following safety-related conditions involving facilities in service:
 - (1) In the case of a pipeline that operates at a hoop stress of 20 percent or more of its specified minimum yield strength, general corrosion that has reduced the wall thickness to less than that required for the maximum allowable operating pressure, and localized corrosion pitting to a degree where leakage might result.
 - (2) In the case of a UNGSF, general corrosion that has reduced the wall thickness of any metal component to less than that required for the well's maximum operating pressure, or localized corrosion pitting to a degree where leakage might result.
 - (3) Unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability of a pipeline or the structural integrity or reliability of a UNGSF that contains, controls or processes gas.

- (4) Any crack or other material defect that impairs the structural integrity or reliability of a UNGSF that contains controls or processes gas.
 - (5) Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of 20 percent or more of its specified minimum yield strength or the serviceability or the structural integrity of a UNGSF.
 - (6) Any malfunction or operating error that causes the pressure - plus the margin (build-up) allowed for operation of pressure limiting or control devices - to exceed either the maximum allowable operating pressure of a distribution or gathering line, the maximum well allowable operating pressure of an underground natural gas storage facility.
 - (7) A leak in a pipeline, or UNGSF containing or processing gas that constitutes an emergency.
 - (8) Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline or UNGSF, that contains or processes gas.
 - (9) For transmission pipelines only, each exceedance of the maximum allowable operating pressure that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices as specified in the applicable requirements of §§ 192.201, 192.620(e), and 192.739. The reporting requirement of this paragraph (a)(9) is not applicable to gathering lines or distribution lines (See paragraph (a)(6) of this section).
- (b) A report is not required for any safety-related condition that:
- (1) Exists on a master meter system, a reporting-regulated gathering pipeline, a Type C gas gathering pipeline with an outside diameter of 12.75 inches or less, a Type C gas gathering pipeline covered by the exception in § 192.9(f)(1) of this subchapter and therefore not required to comply with § 192.9(e)(2)(ii), or a customer-owned service line;
 - (2) Is an incident or results in an incident before the deadline for filing the safety-related condition report;
 - (3) Exists on a pipeline that is more than 220 yards (200 meters) from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway; or
 - (4) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report, except that reports are required for:
 - (i) Conditions under paragraph (a)(1) of this section, unless the condition is localized corrosion pitting on an effectively coated and cathodically protected pipeline and
 - (ii) Any condition under paragraph (a)(9) of this section.
 - (5) Exists on an UNGSF, where a well or wellhead is isolated, allowing the reservoir or cavern and all other components of the facility to continue to operate normally and without pressure restriction.

§ 191.25 Filing Safety-Related Condition Reports

- (a) Each report of a safety-related condition under § 191.23(a)(1) through (9) must be

filed (received by the Associate Administrator) in writing within 5 working days (not including Saturday, Sunday, or Federal holidays) after the day a representative of an operator first determines that the condition exists, but not later than 10 working days after the day a representative of an operator discovers the condition. Separate conditions may be described in a single report if they are closely related. Reporting methods and report requirements are described in paragraph (c) of this section. Each report of a maximum allowable operating pressure exceedance meeting the requirements of criteria in § 191.23(a)(9) for a gas transmission pipeline must be filed (received by the Associate Administrator) in writing within 5 calendar days of the exceedance using the reporting methods and report requirements described in paragraph (c) of this section.

- (b) Reports must be filed by email to *InformationResourcesManager@dot.gov* or by facsimile to (202) 366-7128 and via email to *PIR.Mailbox@arkansas.gov*. For a report made pursuant to §191.23(a)(1) through (8), the report must be headed "Safety-Related Condition Report." For a report made pursuant to § 191.23(a)(9), the report must be headed "Maximum Allowable Operating Pressure Exceedances." All reports must provide the following information:
- (1) Name, principal address, and operator identification number (OPID) of the operator.
 - (2) Date of report.
 - (3) Name, job title, and business telephone number of person submitting the report.
 - (4) Name, job title, and business telephone number of person who determined that the condition exists.
 - (5) Date condition was discovered, and date condition was first determined to exist.
 - (6) Location of condition, with reference to the State (and town, city, or county) or offshore site, and as appropriate, nearest street address, offshore platform, survey station number, milepost, landmark, or name of pipeline.
 - (7) Description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored.
 - (8) The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action.

§ 191.27 Status of Leaks

- (a) Each natural gas distribution operator shall submit to the Commission's Pipeline Safety Office twice annually, no later than January 15th and July 15th, of each calendar year, a leak report.
- (b) The report shall include a caption identifying the report as "Leak Report" along with the name of the operator filing the report.
- (c) Each natural gas distribution operator shall provide on the leak report, the status of all known leaks within its system classified by type of leak, as Class I, II or III.
- (d) Each report shall identify and describe the status of each leak as follows:
 - (1) Identification Number for the leak; and
 - (2) All known leaks as of the beginning of each six-month period; and
 - (3) Those reported/found during the six-month period; and

- (4) Date leak discovered; and
 - (5) The location of each leak, i.e. main, service, riser, meter, regulator station; and
 - (6) Those repaired during the six-month period with date of repair; and
 - (7) Those reported and awaiting repair at the end of the six-month period; and
 - (8) Pipe type, i.e. coated or bare steel, plastic, cast iron; and
 - (9) Leak cause, if known; and
 - (10) Method of how the utility became aware of the leak, i.e. leak survey, customer notification, operator employee.
- (e) The report shall include the signature, full name and title of the utility employee who prepared the report.
 - (f) The above reporting requirement does not apply to master meter operators.

§ 191.29 National Pipeline Mapping System

- (a) Each operator of a gas transmission pipeline or liquefied natural gas facility must provide the following geospatial data to PHMSA for the pipeline or facility:
 - (1) Geospatial data, attributes, metadata and transmittal letter appropriate for use in the National Pipeline Mapping System. Acceptable formats and additional information are specified in the NPMS Operator Standards Manual available at <https://www.npms.phmsa.dot.gov/> or by contacting the PHMSA Geographic Information Systems Manager at (202) 366-4595;
 - (2) The name of and address for the operator; and
 - (3) The name and contact information of a pipeline company employee, to be displayed on a public Web site, who will serve as a contact for questions from the general public about the operator's NPMS data.
- (b) The information required in paragraph (a) of this section must be submitted each year, on or before March 15, representing assets as of December 31 of the previous year. If no changes have occurred since the previous year's submission, the operator must comply with the guidance provided in the NPMS Operator Standards manual available www.npms.phmsa.dot.gov or contact the PHMSA Geographic Information Systems Manager at (202) 366-4595.
- (c) This section does not apply to gathering pipelines.

APPENDIX A TO PART 191 PROCEDURE FOR DETERMINING REPORTING THRESHOLD

I. Property Damage Threshold Formula

Each year after calendar year 2021, the Administrator will publish a notice on PHMSA's website announcing the updates to the property damage threshold criterion that will take effect on July 1 of that year and will remain in effect until the June 30 of the next year. The property damage threshold used in the definition of an *Incident* at § 191.3 shall be determined in accordance with the following formula:

$$T_r = T_p \times \frac{CPI_r}{CPI_p}$$

Where:

T_r is the revised damage threshold,

T_p is the previous damage threshold,

CPI_r is the average Consumer Price Indices for all Urban Consumers (CPI-U) published by the Bureau of Labor Statistics each month during the most recent complete calendar year, and

CPI_p is the average CPI-U for the calendar year used to establish the previous property damage criteria.

**PART 192 - TRANSPORTATION OF NATURAL AND OTHER GAS BY
PIPELINE: MINIMUM SAFETY STANDARDS**

SUBPART A - GENERAL

§ 192.1 Scope

- (a) Part 192 prescribes minimum safety requirements for pipeline facilities and the transportation of gas within the State of Arkansas. Requirements of the Arkansas Gas Pipeline Code shall take precedence over any other requirements pertaining to construction, operation, and maintenance of gas facilities under the jurisdiction of the Arkansas Public Service Commission.
- (b) This part does not apply to gathering of gas through a pipeline that operates at less than 0 p.s.i.g. (0kPa), and through a pipeline that is not a regulated onshore gathering line (as determined in §192.8); however, it shall apply to the gathering, transmission or distribution of gas containing 100 or more parts-per-million of hydrogen sulfide from the custodial transfer meter through any pipeline, rural or non-rural, to and through any pipeline facility that removes hydrogen sulfide, except that portion of such a pipeline or pipeline facility that is located within the fenced boundary of a petroleum refinery.

§ 192.3 Definitions

As used in this part:

Abandoned means permanently removed from service.

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

Administrator means the Administrator of the Pipeline and Hazardous Materials Safety Administration or any person to whom authority in the matter concerned has been delegated by the U.S. Secretary of Transportation.

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

Business District means a location where gas mains are utilized to serve customers that are predominately commercial in nature and where the street and/or sidewalk paving generally extends from the centerline of a thoroughfare to the established building line on either side.

Change to a segment of pipeline means a physical change in the pipeline or significant changes in operating pressure.

Commission means, unless the context otherwise requires, the Arkansas Public Service Commission or any person or entity to whom the Commission has delegated authority in the matter concerned.

Close interval survey means a series of closely and properly spaced pipe-to-electrolyte potential measurements taken over the pipe to assess the adequacy of cathodic protection or to identify locations where a current may be leaving the pipeline that may cause corrosion and for the purpose of quantifying voltage (IR) drops other than those across the structure electrolyte boundary, such as when performed as a current interrupted, depolarized, or native survey.

Composite Materials means materials used to make pipe or components manufactured with a combination of either steel or plastic, or both, and with a reinforcing material to maintain its

circumferential or longitudinal strength.

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

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

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

Distribution center means the initial point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption, as opposed to customers who purchase it for resale, for example:

- (1) At a metering location;
- (2) A pressure reduction location; or
- (3) Where there is a reduction in the volume of gas, such as a lateral off a transmission line.

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

Dry gas or dry natural gas means gas above its dew point and without condensed liquids.

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.

Engineering critical assessment (ECA) means a documented analytical procedure based on fracture mechanics principles, relevant material properties (mechanical and fracture resistance properties), operating history, operational environment, in-service degradation, possible failure mechanisms, initial and final defect sizes, and usage of future operating and maintenance procedures to determine the maximum tolerable sizes for imperfections based upon the pipeline segment maximum allowable operating pressure.

Entirely replaced onshore transmission pipeline segments means, for the purposes of §§ 192.179 and 192.634, where 2 or more miles, in the aggregate, of onshore transmission pipeline have been replaced within any 5 contiguous miles of pipeline within an 24-month period. This definition does not apply to any gathering line.

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

Gathering Line means a pipeline that transports gas from a current production facility to a transmission line or main.

Hard spot means an area on steel pipe material with a minimum dimension greater than two inches (50.8 mm) in any direction and hardness greater than or equal to Rockwell 35 HRC (Brinell 327 HB or Vickers 345 HV¹⁰).

High Pressure Distribution System means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer.

Key Valves means shut off valves in a distribution system or transmission line which may be necessary to isolate segments of a system or line for emergency purposes.

In-line inspection (ILI) means an inspection of a pipeline from the interior of the pipe using an inspection tool also called intelligent or smart pigging. This definition includes tethered and self-

propelled inspection tools.

In-line inspection tool or instrumented internal inspection device means an instrumented device or vehicle that uses a non-destructive testing technique to inspect the pipeline from the inside in order to identify and characterize flaws to analyze pipeline integrity; also known as an intelligent or smart pig.

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

Listed Specification means a specification listed in Section I of Appendix B to Part 192.

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

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

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

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

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

Mobile Home Park means two or more mobile homes located on a contiguous tract of land.

Moderate consequence area means:

- (1) An onshore area that is within a potential impact circle, as defined in § 192.903, containing either:
 - (i) Five or more buildings intended for human occupancy; or
 - (ii) Any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, as defined in the Federal Highway Administration's *Highway Functional Classification Concepts, Criteria and Procedures, Section 3.1* (see: https://www.fhwa.dot.gov/planning/processes/statewide/related/highway_functional_classifications/fcauab.pdf), and that does not meet the definition of high consequence area, as defined in § 192.903.
- (2) The length of the moderate consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle containing either 5 or more buildings intended for human occupancy; or any portion of the paved surface, including shoulders, of any designated interstate, freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, to the outermost edge of the last contiguous potential impact circle that contains either 5 or more buildings intended for human occupancy, or any portion of the paved surface, including shoulders, of any designated interstate, freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes.

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

Notification of potential rupture means the notification to, or observation by, an operator of indicia identified in § 192.635 of a potential unintentional or uncontrolled release of a large volume of gas from a pipeline. This definition does not apply to any gathering line.

Operator means a person who:

- (1) Engages in the transportation of gas; or
- (2) Operates a distribution system within a mobile home park, public housing authority, or multiple building complex if:
 - (A) The system:
 - (i) Is not owned, nor the responsibility of a public or municipal utility; and
 - (ii) Is used to transport gas from a master meter or a public/municipal utility main to consumers who may or may not be metered; and
 - (B) The gas distributed is not consumed solely by the owner/operator.

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

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 p.s.i.g. (1434 kPa) gage at 100°F (38°C).

Petroleum Refinery means an industrial or manufacturing facility or plant primarily engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants or other products through the processing of petroleum crude oil that is subject to:

- (A) The federal Environmental Protection Agency Standards of Performance for New Stationary Sources set forth in Subpart GGG of 40 CFR part 60 or successor regulations;
- (B) The federal *Environmental* Protection Agency Chemical Accident Prevention Provisions set forth in Subparts, A, B, D, E, F, G, and H of 40 CFR Part 68 or successor regulations; and
- (C) The federal Occupational Safety and Health Administration Regulations governing process safety management of highly hazardous chemicals set forth in 29 CFR §1910.119 or successor regulations.

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

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

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

Pipeline Facilities includes without limitation, new and existing pipe, pipe rights-of-way, and any equipment, facility or building used in the transportation of gas or the treatment of gas during the course of transportation of gas.

Private Line System means a natural gas pipeline or pipeline system that is not a master meter

system; is not owned by, nor the responsibility of a public or municipal utility; is used to transport gas that is not consumed solely by the owner/operator from a public or municipal utility meter to consumers who may or may not be metered.

Production Facilities includes without limitation, piping or equipment used in the production, extraction, recovery, lifting, stabilization, separation or treatment of natural gas or associated storage or measurement from the wellhead to a meter where the gas is transferred to a custodian other than the well operator for gathering or transport, commonly known as a “custodial transfer meter.”

Production Process means the extraction of gas from the geological source of supply to the surface of the earth, thence through the lines and equipment used to treat, compress and measure the gas between the wellhead and the meter where it is either sold or delivered to a custodian other than *the well operator* for gathering and transport to a place of sale, sometimes called “custodial transfer meter.”

Rupture-mitigation valve (RMV) means an automatic shut-off valve (ASV) or a remote-control valve (RCV) that a pipeline operator uses to minimize the volume of gas released from the pipeline and to mitigate the consequences of a rupture. This definition does not apply to any gathering line.

Service Line means a distribution line that transports gas from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer’s piping, whichever is further downstream, or at the connection to customer piping if there is no meter.

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

SMYS means specific minimum yield strength, and is:

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

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.

Test Failure means a break or rupture that occurs during strength proof testing of transmission or gathering lines that are of such magnitude as to require repair before continuation of the test.

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

- (1) Transports gas from a gathering line or storage facility to a gas distribution center, storage facility or large volume customer that is not down-stream from a gas distribution center;
- (2) Operates at a hoop stress of 20 percent or more of SMYS;
- (3) Transports gas within a storage field; or
- (4) Is voluntarily designated by the operator as a transmission pipeline.

NOTE: A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

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

Underground natural gas storage facility (UNGSF) means a gas pipeline facility that stores natural gas underground incidental to the transportation of natural gas, including:

- (1) (i) A depleted hydrocarbon reservoir;
- (ii) An aquifer reservoir; or
- (iii) A solution-mined salt cavern.
- (2) In addition to the reservoir or cavern, a UNGSF includes injection, withdrawal, monitoring, and observation wells; wellbores and downhole components; wellheads and associated wellhead piping; wing-valve assemblies that isolate the wellhead from connected piping beyond the wing-valve assemblies; and any other equipment, facility, right-of-way, or building used in the underground storage of natural gas.

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

Welding operator means a person who operates machine or automatic welding equipment.

Weak link means a device or method used when pulling polyethylene pipe, typically through methods such as horizontal directional drilling, to ensure that damage will not occur to the pipeline by exceeding the maximum tensile stresses allowed.

Wrinkle bend means a bend in the pipe that:

- (1) Was formed in the field during construction such that the inside radius of the bend has one or more ripples with:
 - (i) An amplitude greater than or equal to 1.5 times the wall thickness of the pipe, measured from peak to valley of the ripple; or
 - (ii) With ripples less than 1.5 times the wall thickness of the pipe and with a wrinkle length (peak to peak) to wrinkle height (peak to valley) ratio under 12.
- (2)
 - (i) If the length of the wrinkle bend cannot be reliably determined, then *wrinkle bend* means a bend in the pipe where $(h/D)*100$ exceeds 2 when S is less than 37,000 psi (255 MPa), where $(h/D)*100$ exceeds $(47000-S)/10,000 + 1$ for psi [$(324-S)/69 + 1$ for MPa] when S is greater than 37,000 psi (255 MPa) but less than 47,000 psi (324 MPa), and where $(h/D)*100$ exceeds 1 when S is 47,000 psi (324 MPa) or more.
 - (ii) Where:
 - (A) D = Outside diameter of the pipe, in. (mm);
 - (B) h = Crest-to-trough height of the ripple, in. (mm); and
 - (C) S = Maximum operating hoop stress, psi (S/145, MPa).

§ 192.5 Class Locations

- (a) This section classifies pipeline locations for the purposes of this part. The following criteria apply to classifications under this section.
 - (1) A "class location unit" is an area that extends 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline.

- (2) Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.
- (b) Except as provided in paragraph (c) of this section, pipeline locations are classified as follows:
 - (1) A Class 1 location is any class location unit that has 10 or fewer buildings intended for human occupancy.
 - (2) A Class 2 location is any class location unit that has more than 10 but fewer than 46 buildings intended for human occupancy.
 - (3) A Class 3 location is:
 - (i) Any class location unit that has 46 or more buildings intended for human occupancy; or
 - (ii) An area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)
 - (4) A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.
- (c) The boundaries of Class locations 2, 3, and 4 may be adjusted as follows:
 - (1) A Class 4 location ends 220 yards (200 meters) from the nearest building with four or more stories above ground.
 - (2) When all buildings intended for human occupancy within a Class 2 or 3 location are in a single cluster, the class location ends 220 yards (200 meters) from the nearest building in the cluster.
- (d) An operator must have records that document the current class location of each gas transmission pipeline segment and that demonstrate how the operator determined each current class location in accordance with this section.

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

- (a) Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. All approved incorporation by reference (IBR) material is available for inspection at the Pipeline and Hazardous Materials Safety Administration (PHMSA) 1200 New Jersey Avenue SE, Washington, DC 20590; 202-366-4046; <https://www.phmsa.dot.gov/pipeline/regs> and at the National Archives and Records Administration (NARA). Contact PHMSA at: Office of Pipeline Safety, Pipeline and Hazardous Material Safety Administration, 1200 New Jersey Avenue SE, Washington, DC 20590; 202-366-4046; www.phmsa.dot.gov/pipeline/regs. For information on the availability of this material at NARA, visit www.archives.gov/federal-register/cfr/ibr-locations.html or email fr.inspection@nara.gov. It is also available from the sources in the following paragraphs of this section
- (b) American Petroleum Institute (API), 200 Massachusetts Ave. NW, Suite 1100, Washington, DC 20001, and phone: 202-682-8000, website: <https://www.api.org>.
 - (1) API Recommended Practice 5L1, "Recommended Practice for Railroad Transportation of Line Pipe," 7th edition, September 2009, (API RP 5L1), IBR approved for § 192.65(a).

- (2) API Recommended Practice 5LT, "Recommended Practice for Truck Transportation of Line Pipe," First edition, March 2012, (API RP 5LT), IBR approved for § 192.65(c).
 - (3) API Recommended Practice 5LW, "Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels," 3rd edition, September 2009, (API RP 5LW), IBR approved for § 192.65(b).
 - (4) API Recommended Practice 80, "Guidelines for the Definition of Onshore Gas Gathering Lines" 1st edition, April 2000, (API RP 80), IBR approved for § 192.8(a).
 - (5) API Recommended Practice 1162, "Public Awareness Programs for Pipeline Operators," 1st edition, December 2003, (API RP 1162), IBR approved for § 192.616(a), (b), and (c).
 - (6) API Recommended Practice 1165, "Recommended Practice for Pipeline SCADA Displays," First edition, January 2007, (API RP 1165), IBR approved for § 192.631(c).
 - (7) API Specification 5L, Line Pipe, 46th edition, April 2018, including Errata 1 (May 2018), (API Spec 5L); IBR approved for §§ 192.55(e); 192.112(a), (b), (c), (d), and (e); 192.113; appendix B to part 192.
 - (8) API Specification 6D, Specification for Pipeline and Piping Valves, 24th edition, August 2014, including Errata 1 through 10 (October 2014 through July 2021), Addendum 1 (March 2015), and Addendum 2 (June 2016), (API Spec 6D); IBR approved for § 192.145(a).
 - (9) API Standard 1104, Welding of Pipelines and Related Facilities, 21st edition, September 2013, including Errata 1 through 5 (April 2014 through September 2018), Addendum 1 (2014), and Addendum 2 (2016), (API Std 1104); IBR approved for §§ 192.225(a); 192.227(a); 192.229(b) and (c); 192.241(c); appendix B to part 192.
 - (10) API Recommended Practice 1170, "Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage," First edition, July 2015 (API RP 1170), IBR approved for § 192.12.
 - (11) API Recommended Practice 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs," First edition, September 2015, (API RP 1171), IBR approved for § 192.12
- (c) American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016, 800-843-2763; email: CustomerCare@asme.org; website: www.asme.org/.
- (1) (ASME/ANSI B16.1-2005, "Gray Iron Pipe Flanges and Flanged Fittings: (Classes 25, 125, and 250)," August 31, 2006, (ASME/ANSI B16.1), IBR approved for § 192.147(c).
 - (2) ASME/ANSI B16.5-2003, "Pipe Flanges and Flanged Fittings," October 2004, (ASME/ANSI B16.5), IBR approved for §§ 192.147(a), 192.607(f).
 - (3) ASME B16.40-2008, "Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems," March 18, 2008, approved by ANSI, (ASME B16.40-2008), IBR approved for Item I, Appendix B to Part 192.
 - (4) ASME/ANSI B31G-1991 (Reaffirmed 2004, "Manual for Determining the Remaining Strength of Corroded Pipelines," 2004, (ASME/ANSI B31G), IBR approved for §§ 192.485(c), 192.632(a), 192.712(b), and 192.933(a).

- (5) ASME B31.8-2018, Gas Transmission and Distribution Piping Systems, Issued November 20, 2018, (ASME B31.8); IBR approved for §§ 192.112(b); 192.619(a).
 - (6) ASME/ANSI B31.8S-2004, "Supplement to B31.8 on Managing System Integrity of Gas Pipelines," approved January 14, 2005 (ASME/ANSI B31.8S-2004), IBR approved for §§ 192.714(d); 192.933(d).
 - (7) ASME B31.8S-2018, Managing System Integrity of Gas Pipelines, Issued November 28, 2018, (ASME B31.8S); IBR approved for §§ 192.13(d); 192.714(c); 192.903 note to Potential impact radius; 192.907 introductory text and (b); 192.911 introductory text, (i), and (k) through (m); 192.913(a) through (c); 192.917(a) through (e); 192.921(a); 192.923(b); 192.925(b); 192.933(c); 192.935(b); 192.937(c); 192.939(a); 192.945(a).
 - (8) ASME B36.10M-2018, Welded and Seamless Wrought Steel Pipe, Issued October 12, 2018, (ASME B36.10M); IBR approved for § 192.279.
 - (9) ASME Boiler & Pressure Vessel Code, Section VIII, Division 2 "Rules, Rules for Construction of Pressure Vessels" 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 2), IBR approved for §§ 192.153(b), (d); and 192.165(b).
 - (10) ASME Boiler & Pressure Vessel Code, Section IX: "Qualification Standard for Welding and Brazing Procedures, Welders, Brazers, and Welding and Brazing Operators," 2007 edition, July 1, 2007, ASME BPVC, Section IX, IBR approved for §§ 192.225(a); 192.227(a); and Item II, Appendix B to Part 192.
 - (11) API Standard 1163, "In-Line Inspection Systems Qualification," Second edition, April 2013, Reaffirmed August 2018, (API STD 1163), IBR approved for § 192.493.
- (d) American Society for Nondestructive Testing (ASNT), P.O. Box 28518, 1711 Arlingate Lane, Columbus, OH 43228, phone: 800-222-2768, website: <https://www.asnt.org/>.
- (1) ANSI/ASNT ILI-PQ-2005 (2010), "In-line Inspection Personnel Qualification and Certification," Reapproved October 11, 2010, (ANSI/ASNT-PQ), IBR approved for § 192.493.
 - (2) [Reserved]
- (e) ASTM International (ASTM), 100 Barr Harbor Drive, P.O. Box C700, West Conshohocken, PA 19428; phone: (610) 832-9585; email: service@astm.org; website: www.astm.org.
- (1) ASTM A53/A53M-20, Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless, approved July 1, 2020, (ASTM A53/A53M); IBR approved for § 192.113; appendix B to part 192.
 - (2) ASTM A106/A106M-19A, Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service, approved November 1, 2019, (ASTM A106/A106M); IBR approved for § 192.113; appendix B to part 192.
 - (3) ASTM A333/A333M-18, Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service and Other Applications with Required Notch Toughness, approved November 1, 2018, (ASTM A333/A333M); IBR approved for § 192.113; appendix B to part 192.
 - (4) ASTM A372/A372M-10, "Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels," approved October 1, 2010, (ASTM A372/A372M), IBR approved for § 192.177(b).
 - (5) ASTM A381/A381M-18, Standard Specification for Metal-Arc-Welded Carbon or High-Strength Low-Alloy Steel Pipe for Use with High-Pressure Transmission

- Systems, approved November 1, 2018, (ASTM A381); IBR approved for § 192.113; appendix B to part 192.
- (6) ASTM A578/A578M-96 (reapproved 2001), "Standard Specification for Straight-Beam Ultrasonic Examination of Plain and Clad Steel Plates for Special Applications," (ASTM A578/A578M), IBR approved for § 192.112(c).
 - (7) ASTM A671/A671M-20, Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures, approved March 1, 2020, (ASTM A671/A671M); IBR approved for § 192.113; appendix B to part 192.
 - (8) ASTM A672/A672M 09, "Standard Specification for Electric- Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperature," approved October 1, 2009, (ASTM A672/672M), IBR approved for § 192.113 and Item I, Appendix B to Part 192.
 - (9) ASTM A691/A691M-19, Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures, approved November 1, 2019, (ASTM A691/A691M); IBR approved for § 192.113; appendix B to part 192.
 - (10) ASTM D638-03, "Standard Test Method for Tensile Properties of Plastics," 2003, (ASTM D638), IBR approved for § 192.283(a) and (b).
 - (11) ASTM D2513-18a, "Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings," approved August 1, 2018, (ASTM D2513), IBR approved for Item I, Appendix B to Part 192.
 - (12) ASTM D2517-00, "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings," (ASTM D 2517), IBR approved for §§ 192.191(a); 192.281(d); 192.283(a); and Item I, Appendix B to Part 192.
 - (13) ASTM D2564-12, "Standard Specification for Solvent Cements for Poly (Vinyl Chloride)(PVC) Plastic Piping Systems," August 1, 2012, (ASTM D2564- 12), IBR approved for §192.281(b)(2).
 - (14) ASTM F1055- 98 (Reapproved 2006), "Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing," March 1, 2006, (ASTM F1055-98 (2006)), IBR approved for § 192.283(a), Item I, Appendix B to Part 192.
 - (15) ASTM F1055-98 (Reapproved 2006), "Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing," March 1,2006, ASTM F1055-98 (2006)), IBR approved for §192.283(a), Item I Appendix B to Part 192 ASTM F1924-12), "Standard Specification for Plastic Mechanical Fittings for Use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing, " April 1, 2012 (ASTM F1924-12), IBR approved for Item 1 Appendix B to Part 192.
 - (16) ASTM F1948-12, (Standard Specification for Metallic Mechanical Fittings for Use on Outside Diameter Controlled Thermoplastic Gas Distribution Pipe and Tubing," April 1, 2012, (ASTM F1948-12), IBR approved for Item I, Appendix B to Part 192.
 - (17) ASTM F1973-13, "Standard Specification for Factory Assembled Anodeless Risers and Transition Fittings in Polyethylene (PE) and Polyamide 11 (PA11) and Polyamide 12 (PA12) Fuel Gas Distribution Systems," May 1, 2013, (ASTM F1973-13), IBR approved for §192.204(b); and Item I, Appendix B to Part 192.
 - (18) ASTM F2145-13, 'Standard Specification for Polyamide 11 (PA11) and Polyamide 12 (PA12) Mechanical Fittings for Use on Outside Diameter Controlled Polyamide 11 and Polyamide 12 Pipe and Tubing," May 1, 2013, (ASTM F2145-13), IBR

- approved for Item 1, Appendix B to Part 192.
- (19) ASTM F2600-09, "Standard Specification for Electrofusion Type Polyamide-11 Fittings for Outside Diameter Controlled Polyamide-11 Pipe and Tubing," April 1, 2009, (ASTM F 2600-09) IBR approved for Item I, Appendix B to Part 192.
 - (20) ASTM F2620-19, "Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings," approved February 1, 2019, (ASTM F2620), IBR approved for §§192.281(c) and 192.285(b).
 - (21) ASTM 2767-12, "Specification for Electrofusion Type Polyamide-12 Fittings for Outside Diameter Controlled Polyamide-12 Pipe and Tubing for Gas Distribution." Oct 15, 2012, (ASTM F2767-12), IBR approved for Item I, Appendix B to Part 192.
 - (22) ASTM F2785-12, "Standard Specification for Polyamide 12 Gas Pressure Pipe, Tubing and Fittings," Aug. 1 2012, (ASTM F2785-12), IBR approved for Item 1, Appendix B to Part 192.
 - (23) ASTM F2817-10, "Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair," Feb. 1, 2010 (ASTM F2817-10), IBR approved for Item 1, Appendix B to Part 192.
 - (24) ASTM F2945-12a "Standard Specification for Polyamide 11 Gas Pressure Pipe, Tubing and Fittings," Nov 27, 2012 (ASTM F2945-12a), IBR approved for Item I, Appendix B to Part 192.
- (f) [Reserved]
 - (g) Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park St. NE., Vienna, VA 22180, phone: 703-281-6613, email: info@msshq.org; website: <http://www.msshq.org/>.
 - (1) ANSI/MSS SP-44-2019, Steel Pipeline Flanges, published April 2020, (MSS SP-44); IBR approved for § 192.147(a).
 - (2) [Reserved]
 - (h) NACE International (NACE), 1440 South Creek Drive, Houston, TX 77084: phone: 281-228-6223 or 800-797-6223 Web site: <http://www.nace.org/Publications/>.
 - (1) NACE Standard Practice 0102-2010 "In-Line Inspection of Pipelines," Revised 2010-03-13, (NACE SP0102), IBR approved for §§ 192.150(a) and 192.493.
 - (2) NACE SP0204-2008, Standard Practice, "Stress Corrosion Cracking (SCC) Direct Assessment Methodology," reaffirmed September 18, 2008, (NACE SP0204); IBR approved for §§ 192.923(b); 192.929(b) introductory text, (b)(1) through (3), (b)(5) introductory text, and (b)(5)(i).
 - (3) NACE SP0206-2006, Standard Practice, "Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)," approved December 1, 2006, (NACE SP0206), IBR approved for §§ 192.923(b); 192.927(b), (c) introductory text, and (c)(1) through (4).
 - (4) ANSI/NACE SP0502-2010, Standard Practice, "Pipeline External Corrosion Direct Assessment revised June 24, 2010, (NACE SP0502), IBR approved for §§ 192.923(b); 192.925(b); 192.931(d); 192.935(b) and 192.939(a).
 - (i) National Fire Protection Association (NFPA), 1 Batterymarch Park, Quincy, Massachusetts 02169, phone: (617) 984-7275; website: www.nfpa.org.
 - (1) NFPA-30 (2012), "Flammable and Combustible Liquids Code," 2012 edition, June 20, 2011, including Errata 30-12-1 (September 27, 2011) and Errata 30-12-2 (November 14, 2011), (NFPA-30), IBR approved for § 192.735(b).

- (2) NFPA 58, Liquefied Petroleum Gas Code, 2020 edition, effective August 25, 2019, (NFPA 58); IBR approved for § 192.11.
 - (3) NFPA 59, Utility LP-Gas Plant Code, 2018 edition, effective September 6, 2017, (NFPA 59); IBR approved for § 192.11.
 - (4) NFPA 70, National Electrical Code (NEC), 2017 edition, effective August 24, 2016, (NFPA 70); IBR approved for §§ 192.163(e); 192.189(c).
- (j) Pipeline Research Council International, Inc. (PRCI), c/o Technical Toolboxes, 3801 Kirby Drive, Suite 520, P.O. Box 980550, Houston, TX 77098, phone: 713-630-0505, toll free: 866-866-6766, Web site: <http://www.ttoolboxes.com/>. (Contract number PR3-805.)
- (1) AGA, Pipeline Research Committee Project, PR-3-805, “A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe,” (December 22, 1989), (PRCI PR-3-805 (R-STRENG)), IBR approved for §§ 192.485(c); 192.632(a); 192.712(b); 192.933(a) and (d).
 - (2) [Reserved]
- (k) Plastics Pipe Institute, Inc. (PPI), 105 Decker Court, Suite 825 Irving TX 75062, phone: 469-499-1044, <http://www.plasticpipe.org/>.
- (1) PPI TR-3/2012, HDB/HDS/PDB/SDB/MRS/CRS, Policies, “Policies and Procedures for Developing Hydrostatic Design Basis (HDB), Hydrostatic Design Stresses (HDS), Pressure Design Basis (PDB), Strength Design Basis (SDB), Minimum Required Strength (MRS) Ratings, and Categorized Required Strength (CRS) for Thermoplastic Piping Materials or Pipe,” updated November 2012, (PPI TR-3/2012), IBR approved for §192.121.
 - (2) PPI TR-4, HDB/HDS/SDB/MRS, Listed Materials, “PPI Listing of Hydrostatic Design Basis (HDB), Hydrostatic Design Stress (HDS), Strength Design Basis (SDB), Pressure Design Basis (PDB) and Minimum Required Strength (MRS) Rating For Thermoplastic Piping Materials or Pipe,” updated March 2011, (PPI TR-4/2012), IBR approved for § 192.121.

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

- (a) An operator must use API RP 80 (incorporated by reference, see § 192.7), to determine if an onshore pipeline (or part of a connected series of pipelines) is an onshore gathering line. The determination is subject to the limitations listed below. After making this determination, an operator must determine if the onshore gathering line is a regulated onshore gathering line under paragraph (b) of this section.
- (1) The beginning of gathering, under section 2.2(a)(1) of API RP 80, may not extend beyond the furthest downstream point in a production operation as defined in section 2.3 of API RP 80. This furthest downstream point does not include equipment that can be used in either production or transportation, such as separators or dehydrators, unless that equipment is involved in the processes of “production and preparation for transportation or delivery of hydrocarbon gas” within the meaning of “production operation.”
 - (2) The endpoint of gathering, under section 2.2(a)(1)(A) of API RP 80, may not extend beyond the first downstream natural gas processing plant, unless the operator can demonstrate, using sound engineering principles, that gathering extends to a further downstream plant.
 - (3) If the endpoint of gathering, under section 2.2(a)(1)(C) of API RP 80, is determined by the commingling of gas from separate production fields, the fields may not be more than 50 miles from each other, unless the Administrator finds a longer separation distance is justified in a particular case (see 49 CFR § 190.9).
 - (4) The endpoint of gathering, under section 2.2(a)(1)(D) of API RP 80, may not extend beyond the furthest downstream compressor used to increase gathering line pressure for delivery to another pipeline.
 - (5) For new, replaced, relocated, or otherwise changed gas gathering pipelines installed after May 16, 2022, the endpoint of gathering under sections 2.2(a)(1)(E) and 2.2.1.2.6 of API RP 80 (incorporated by reference, see § 192.7) – also known as “incidental gathering” – may not be used if the pipeline terminates 10 or more miles downstream from the furthest downstream endpoint as defined in paragraphs 2.2(a)(1)(A) through (a)(1)(D) of API RP 80 (incorporated by reference, see § 192.7) and this section. If an “incidental gathering” pipeline is 10 miles or more in length, the entire portion of the pipeline that is designated as an incidental gathering line under 2.2(a)(1)(E) and 2.2.1.2.6 of API RP 80 shall be classified as a transmission pipeline subject to all applicable regulations in this chapter for transmission pipelines.
- (b) Each operator must determine and maintain for the life of the pipeline records documenting the methodology by which it calculated the beginning and end points of each onshore gathering pipeline it operates, as described in the second column of table 1 to paragraph (c)(2) of this section, by:
- (1) November 16, 2022, or before the pipeline is placed into operation, whichever is later; or
 - (2) An alternative deadline approved by the Pipeline and Hazardous Materials Safety Administration (PHMSA). The operator must notify PHMSA and State or local pipeline safety authorities, as applicable, no later than 90 days in advance of the deadline in paragraph (b)(1) of this section. The notification must be made in accordance with § 192.18 and must include the following information:
 - i. Description of the affected facilities and operating environment;

- ii. Justification for an alternative compliance deadline; and
 - iii. Proposed alternative deadline.
- (c) For purposes of part 191 of this chapter and § 192.9, the term “regulated onshore gathering pipeline” means:
- (1) Each Type A, Type B, or Type C onshore gathering pipeline (or segment of onshore gathering pipeline) with a feature described in the second column of table 1 to paragraph (c)(2) of this section that lies in an area described in the third column; and
 - (2) As applicable, additional lengths of pipeline described in the fourth column to provide a safety buffer:

Table 1 to Paragraph (c)(2)

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

		fewer than 46 dwellings; or (c) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1000 feet (305 m) of pipeline and including 5 or more dwellings	
C	Outside diameter greater than or equal to 8.625 inches and any of the following: -Metallic and the MAOP produces a hoop stress of 20 percent or more of SMYS; -If the stress level is unknown, segment is metallic and the MAOP is more than 125 psig (862 kPa); or -Non-metallic and the MAOP is more than 125 psig (862 kPa)	Class 1 location	None.
R	-All other onshore gathering lines	Class 1 and Class 2 locations	None.

- (3) A Type R gathering line is subject to reporting requirements under part 191 of this chapter but is not a regulated onshore gathering line under this part.
- (4) For the purpose of identifying Type C lines in table 1 to paragraph (c)(2) of this section, if an operator has not calculated MAOP consistent with the methods at § 192.619(a) or (c)(1), the operator must either:
 - (i) Calculate MAOP consistent with the methods at § 192.619(a) or (c)(1); or
 - (ii) Use as a substitute for MAOP the highest operating pressure to which the segment was subjected during the preceding 5 operating years.

§ 192.9 What requirements apply to gathering lines?

- (a) *Requirements.* An operator of a gathering line must follow the safety requirements of this part as prescribed by this section.
- (b) *Offshore lines.* An operator of an offshore gathering line must comply with requirements of this part applicable to transmission lines, except the requirements in §§ 192.13(d), 192.150, 192.285(e), 192.319(d) through (g), 192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.465(d), 192.485(c), 192.493, 192.506, 192.607, 192.613(c), 192.619(e), 192.624, 192.710, 192.712, and 192.714 and in subpart O of this

part.

- (c) *Type A lines.* An operator of a Type A regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in §§192.13(d), 192.150, 192.285(e), 192.319(d) through (g), 192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c), 192.493, 192.506, 192.607, 192.613(c), 192.619(e), 192.624, 192.710, 192.712, and 192.714 and in subpart O of this part. However, operators of a Type A regulated onshore gathering line in a Class 2 location may demonstrate compliance with subpart N by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks. Further, operators of Type A regulated onshore gathering lines are exempt from the requirements of §§ 192.179(e) through (g), 192.610, 192.617(b) through (d), 192.634, 192.635, 192.636, and 192.745(c) through (f). Lastly, operators of Type A regulated onshore gathering lines are exempt from the requirements of § 192.615 (but an operator of a Type A regulated onshore gathering line must comply with the requirements of 49 CFR 192.615, effective as of October 4, 2022).
- (d) *Type B lines.* An operator of a Type B regulated onshore gathering line must comply with the following requirements:
- (1) If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this part applicable to transmission lines, compliance with §§ 192.67, 192.127, 192.179(e) and (f), 192.205, 192.227(c), 192.285(e), 192.319(d) through (g), 192.506, 192.634, and 192.636 is not required.;
 - (2) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines except the requirements in §§192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c), and 192.493;
 - (3) If the pipeline contains plastic pipe or components, the operator must comply with all applicable requirements of this part for plastic pipe components;
 - (4) Carry out a damage prevention program under § 192.614;
 - (5) Establish a public education program under § 192.616;
 - (6) Establish the MAOP of the line under § 192.619(a), (b), and (c);
 - (7) Install and maintain line markers according to the requirements for transmission lines in § 192.707; and
 - (8) Conduct leakage surveys in accordance with the requirements for transmission lines in § 192.706 using leak detection equipment and promptly repair hazardous leaks in accordance with § 192.703(c).
- (e) *Type C lines.* The requirements for Type C gathering lines are as follows:
- (1) An operator of a Type C onshore gathering line with an outside diameter greater than or equal to 8.625 inches must comply with the following requirements:
 - (i) Except as provided in paragraph (h) of this section for pipe and components made with composite materials, the design, installation, construction, initial inspection, and initial testing of a new, replaced, relocated, or otherwise changed Type C gathering line, must be done in accordance with the requirements in subparts B through G and J of this part applicable to transmission lines. Compliance with §§ 192.67, 192.127, 192.179(e) and (f), 192.205, 192.227(c), 192.285(e), 192.319(d) through

- (g), and 192.506, 192.634, and 192.636 is not required.
- (ii) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines except for §§192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c), and 192.493;
 - (iii) Carry out a damage prevention program under § 192.614;
 - (iv) Develop and implement procedures for emergency plans in accordance with § 192.615, effective as of October 4, 2022;
 - (v) Develop and implement a written public awareness program in accordance with 192.616;
 - (vi) Install and maintain line markers according to the requirements for transmission lines in §192.707; and
 - (vii) Conduct leakage surveys in accordance with the requirements for transmission lines in § 192.706 using leak-detection equipment, and promptly repair hazardous leaks in accordance with § 192.703(c).
- (2) An operator of a Type C onshore gathering line with outside diameter greater than 12.75 inches must comply with the requirements paragraph (e)(1) of this section and the following:
- (i) If the pipeline contains plastic pipe, the operator must comply with all applicable requirements of this part for plastic pipe or components. This does not include pipe and components made of composite materials that incorporate plastic in the design; and
 - (ii) Establish the MAOP of the pipeline under § 192.619(a) or (c) and maintain records used to establish the MAOP for the life of the pipeline.
- (f) *Exceptions.*
- (1) Compliance with paragraphs (e)(1)(ii), (v), (vi), and (vii) and (e)(2)(i) and (ii) of this section is not required for pipeline segments that are 16 inches or less in outside diameter if one of the following criteria are met:
 - (i) *Method 1.* The segment is not located within a potential impact circle containing a building intended for human occupancy or other impacted site. The potential impact circle must be calculated as specified in § 192.903, except that a factor of 0.73 must be used instead of 0.69. The MAOP used in this calculation must be determined and documented in accordance with paragraph (e)(2)(ii) of this section.
 - (ii) *Method 2.* The segment is not located within a class location unit (see § 192.5) containing a building intended for human occupancy or other impacted site.
 - (2) Paragraph (e)(1)(i) of this section is not applicable to pipeline segments 40 feet or shorter in length that are replaced, relocated, or changed on a pipeline existing on or before May 16, 2022.
 - (3) For purposes of this section, the term “building intended for human occupancy or other impacted site” means any of the following:
 - (i) Any building that may be occupied by humans, including homes, office buildings, factories, outside recreation areas, plant facilities, etc.;

- (ii) A small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12 month period (the days and weeks need not be consecutive); or
 - (iii) Any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes.
- (g) *Compliance deadlines.* An operator of a regulated onshore gathering line must comply with the following deadlines, as applicable.
- (3) An operator of a new, replaced, relocated, or otherwise changed line must be in compliance with the applicable requirements of this section by the date the line goes into service, unless an exception in § 192.13 applies.
 - (4) If a Type A or Type B regulated onshore gathering line existing on April 14, 2006 was not previously subject to this part, an operator has until the date stated in the second column to comply with the applicable requirement for the line listed in the first column, unless the Administrator finds a later deadline is justified in a particular case:

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

- (3) If, after April 14, 2006, a change in class location or increase in dwelling density causes an onshore gathering line to be a regulated onshore gathering line, the operator has 1 year for Type B lines and 2 years for Type A lines after the line becomes a regulated onshore gathering line to comply with this section.
- (4) If a Type C gathering pipeline existing on or before May 16, 2022, was not previously subject to this part, an operator must comply with the applicable requirements of this section, except for paragraph (h) of this section, on or before:
 - (i) May 16, 2023; or
 - (ii) An alternative deadline approved by PHMSA. The operator must notify PHMSA and State or local pipeline safety authorities, as applicable, not later than 90 days in advance of the deadline in paragraph (b)(1) of this section. The notification must be made in accordance with § 192.18 and must include a description of the affected facilities and operating environment, the proposed alternative deadline for each affected requirement, the justification for each alternative compliance deadline, and actions the operator will take to ensure the safety of affected facilities.
- (5) If, after May 16, 2022, a change in class location, an increase in dwelling density, or an increase in MAOP causes a pipeline to become a Type C gathering pipeline,

or causes a Type C gathering pipeline to become subject to additional Type C requirements (see paragraph (f) of this section), the operator has 1 year after the pipeline becomes subject to the additional requirements to comply with this section.

- (h) *Composite Materials.* Pipe and components made with composite materials not otherwise authorized for use under this part may be used on Type C gathering pipelines if the following requirements are met:
- (1) Steel and plastic pipe and components must meet the installation, construction, initial inspection, and initial testing requirements in subparts B through G and J of this part applicable to transmission lines.
 - (2) Operators must notify PHMSA in accordance with § 192.18 at least 90 days prior to installing new or replacement pipe or components made of composite materials otherwise not authorized for use under this part in a Type C gathering pipeline. The notifications required by this section must include a detailed description of the pipeline facilities in which pipe or components made of composite materials would be used, including:
 - (i) The beginning and end points (stationing by footage and mileage with latitude and longitude coordinates) of the pipeline segment containing composite pipeline material and the counties and States in which it is located;
 - (ii) A general description of the right-of-way including high consequence areas, as defined in § 192.905;
 - (iii) Relevant pipeline design and construction information including the year of installation, the specific composite material, diameter, wall thickness, and any manufacturing and construction specifications for the pipeline;
 - (iv) Relevant operating information, including MAOP, leak and failure history, and the most recent pressure test (identification of the actual pipe tested, minimum and maximum test pressure, duration of test, any leaks and any test logs and charts) or assessment results;
 - (v) An explanation of the circumstances that the operator believes make the use of composite pipeline material appropriate and how the design, construction, operations, and maintenance will mitigate safety and environmental risks;
 - (vi) An explanation of procedures and tests that will be conducted periodically over the life of the composite pipeline material to document that its strength is being maintained;
 - (vii) Operations and maintenance procedures that will be applied to the alternative materials. These include procedures that will be used to evaluate and remediate anomalies and how the operator will determine safe operating pressures for composite pipe when defects are found;
 - (viii) An explanation of how the use of composite pipeline material would be in the public interest; and
 - (ix) A certification signed by a vice president (or equivalent or higher officer) of the operator's company that operation of the applicant's pipeline using composite pipeline material would be consistent with pipeline safety.
 - (3) Repairs or replacements using materials authorized under this part do not require

notification under this section.

§192.12 Underground natural gas storage facilities

Underground natural gas storage facilities (“UNGSFs”), as defined in §192.3, are not subject to any requirements of this part aside from this section.

(a) *Salt cavern UNGSFs.*

- (1) Each UNGSF that uses a solution-mined salt cavern for natural gas storage and was constructed after March 13, 2020, must meet all the provisions of API RP 1170 (incorporated by reference, see § 192.7), the provisions of section 8 of API RP 1171 (incorporated by reference, see § 192.7) that are applicable to the physical characteristics and operations of a solution-mined salt cavern UNGSF, and paragraphs (c) and (d) of this section prior to commencing operations.
- (2) Each UNGSF that uses a solution-mined salt cavern for natural gas storage and was constructed between July 18, 2017, and March 13, 2020, must meet all the provisions of API RP 1170 (incorporated by reference, see § 192.7) and paragraph (c) of this section prior to commencing operations, and must meet all the provisions of section 8 of API RP 1171 (incorporated by reference, see § 192.7) that are applicable to the physical characteristics and operations of a solution-mined salt cavern UNGSF, and paragraph (d) of this section, by March 13, 2021.
- (3) Each UNGSF that uses a solution-mined salt cavern for natural gas storage and was constructed on or before July 18, 2017, must meet the provisions of API RP 1170 (incorporated by reference, see § 192.7), sections 9, 10, and 11, and paragraph (c) of this section, by January 18, 2018, and must meet all provisions of section 8 of API RP 1171 (incorporated by reference, see § 192.7) that are applicable to the physical characteristics and operations of a solution-mined salt cavern UNGSF, and paragraph (d) of this section, by March 13, 2021.

(b) *Depleted hydrocarbon and aquifer reservoir UNGSFs.*

- (1) Each UNGSF that uses a depleted hydrocarbon reservoir or an aquifer reservoir for natural gas storage and was constructed after July 18, 2017, must meet all provisions of API RP 1171 (incorporated by reference, see § 192.7), and paragraphs (c) and (d) of this section, prior to commencing operations.
- (2) Each UNGSF that uses a depleted hydrocarbon reservoir or an aquifer reservoir for natural gas storage and was constructed on or before July 18, 2017, must meet the provisions of API RP 1171 (incorporated by reference, see § 192.7), sections 8, 9, 10, and 11, and paragraph (c) of this section, by January 18, 2018, and must meet all provisions of paragraph (d) of this section by March 13, 2021.

(c) *Procedural manuals.* Each operator of a UNGSF must prepare and follow for each facility one or more manuals of written procedures for conducting operations, maintenance, and emergency preparedness and response activities under paragraphs (a) and (b) of this section. Each operator must keep records necessary to administer such procedures and review and update these manuals at intervals not exceeding 15 months, but at least once each calendar year. Each operator must keep the appropriate parts of these manuals accessible at locations where UNGSF work is being performed. Each operator must have written procedures in place before commencing operations or beginning an activity not yet implemented.

(d) *Integrity management program—*

- (1) *Integrity management program elements.* The integrity management program for each UNGSF under this paragraph (d) must consist, at a minimum, of a framework developed under API RP 1171 (incorporated by reference, see § 192.7), section 8 (“Risk Management for Gas Storage Operations”), and that also describes how relevant decisions will be made and by whom. An operator must make continual improvements to the program and its execution. The integrity management program must include the following elements:
 - (i) A plan for developing and implementing each program element to meet the requirements of this section;
 - (ii) An outline of the procedures to be developed;
 - (iii) The roles and responsibilities of UNGSF staff assigned to develop and implement the procedures required by this paragraph (d);
 - (iv) A plan for how staff will be trained in awareness and application of the procedures required by this paragraph (d);
 - (v) Timelines for implementing each program element, including the risk analysis and baseline risk assessments; and
 - (vi) A plan for how to incorporate information gained from experience into the integrity management program on a continuous basis.
- (2) *Integrity management baseline risk-assessment intervals.* No later than March 13, 2024, each UNGSF operator must complete the baseline risk assessments of all reservoirs and caverns, and at least 40% of the baseline risk assessments for each of its UNGSF wells (including wellhead assemblies), beginning with the highest-risk wells, as identified by the risk analysis process. No later than March 13, 2027, an operator must complete baseline risk assessments on all its wells (including wellhead assemblies). Operators may use prior risk assessments for a well as a baseline (or part of the baseline) risk assessment in implementing its initial integrity management program, so long as the prior assessments meet the requirements of API RP 1171 (incorporated by reference, see § 192.7), section 8, and continue to be relevant and valid for the current operating and environmental conditions. When evaluating prior risk-assessment results, operators must account for the growth and effects of indicated defects since the time the assessment was performed.
- (3) *Integrity management re-assessment intervals.* The operator must determine the appropriate interval for risk assessments under API RP 1171 (incorporated by reference, see § 192.7), subsection 8.7.1, and this paragraph (d) for each reservoir, cavern, and well, using the results from earlier assessments and updated risk analyses. The re-assessment interval for each reservoir, cavern, and well must not exceed seven years from the date of the baseline assessment for each reservoir, cavern, and well.
- (4) *Integrity management procedures and recordkeeping.* Each UNGSF operator must establish and follow written procedures to carry out its integrity management program under API RP 1171 (incorporated by reference, see § 192.7), section 8 (“Risk Management for Gas Storage Operations”), and this paragraph (d). The operator must also maintain, for the useful life of the UNGSF, records that demonstrate compliance with the requirements of this paragraph (d). This includes records developed and used in support of any identification, calculation, amendment, modification, justification, deviation, and determination made, and any action taken to implement and evaluate any integrity management program

element.

§ 192.13 What general requirements apply to pipelines regulated under this part?

- (a) No person may operate a segment of pipeline listed in the first column of paragraph (a)(3) of this section that is readied for service after the date in the second column, unless:
 - (1) The pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this part; or
 - (2) The pipeline qualifies for use under this part according to the requirements in § 192.14.
 - (3) The compliance deadlines are as follows:

Pipeline	Date
(i) Offshore gathering pipeline	July 31, 1977
(ii) Regulated onshore gathering pipeline to which this part did not apply until April 14, 2006	March 15, 2007
(iii) Regulated onshore gathering pipeline to which this part did not apply until May 16, 2022	May 16, 2023
(iv) All other pipelines	March 12, 1971

- (b) No person may operate a segment of pipeline listed in the first column of this paragraph (b) that is replaced, relocated, or otherwise changed after the date in the second column of this paragraph (b), unless the replacement, relocation or change has been made according to the requirements in this part.

Pipeline	Date
(1) Offshore gathering pipeline	July 31, 1977
(2) Regulated onshore gathering pipeline to which this part did not apply until April 14, 2006	March 15, 2007
(3) Regulated onshore gathering pipeline to which this part did not apply until May 16, 2022	May 16, 2023
(4) All other pipelines	November 12, 1970

- (c) Each operator shall maintain, modify as appropriate, and follow the plans, procedures, and programs that it is required to establish under this part.
- (d) Each operator of an onshore gas transmission pipeline must evaluate and mitigate, as necessary, significant changes that pose a risk to safety or the environment through a management of change process. Each operator of an onshore gas transmission pipeline must develop and follow a management of change process, as outlined in ASME B31.8S, section 11 (incorporated by reference, see § 192.7), that addresses technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline or processes, whether permanent or temporary. A management of change process must include the following: reason for change, authority for approving changes, analysis of implications, acquisition of required work permits, documentation, communication of change to affected parties, time limitations, and qualification of staff. For pipeline segments other than those covered in subpart O of this part, this

management of change process must be implemented by February 26, 2024. The requirements of this paragraph (d) do not apply to gas gathering pipelines. Operators may request an extension of up to 1 year by submitting a notification to PHMSA at least 90 days before February 26, 2024, in accordance with § 192.18. The notification must include a reasonable and technically justified basis, an up-to-date plan for completing all actions required by this section, the reason for the requested extension, current safety or mitigation status of the pipeline segment, the proposed completion date, and any needed temporary safety measures to mitigate the impact on safety.

§ 192.14 Conversion to Service Subject to this Part

- (a) A steel pipeline previously used in service not subject to this part qualifies for use under this part if the operator prepares and follows a written procedure to carry out the following requirements:
 - (1) The design, construction, operation, and maintenance history of the pipeline must be reviewed and, where sufficient historical records are not available, appropriate tests must be performed to determine if the pipeline is in a satisfactory condition for safe operation.
 - (2) The pipeline right-of-way, all above-ground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline.
 - (3) All known unsafe defects and conditions must be corrected in accordance with this part.
 - (4) The pipeline must be tested in accordance with Subpart J of this part to substantiate the maximum allowable operating pressure permitted by Subpart L of this part.
- (b) Each operator must keep for the life of the pipeline a record of investigations, tests, repairs, replacements, and alterations made under the requirements of paragraph (a) of this section.
- (c) An operator converting a pipeline from service not previously covered by this part must notify PHMSA 60 days before the conversion occurs as required by § 191.22 of this chapter.

§ 192.15 Rules of Regulatory Construction

- (a) As used in this part:
 - Includes** means "including but not limited to."
 - May** means "is permitted to" or "is authorized to."
 - May not** means "is not permitted to" or "is not authorized to."
 - Shall** is used in the mandatory and imperative sense.
- (b) In this part:
 - (1) Words importing the singular include the plural;
 - (2) Words importing the plural include the singular; and
 - (3) Words importing the masculine gender include the feminine.

§ 192.16 Customer Notification

- (a) This section applies to each operator of a service line who does not maintain the customer's buried piping up to entry of the first building downstream, or, if the customer's buried piping does not enter a building, up to the principal gas utilization equipment or the first fence (or wall) that surrounds that equipment. For the purpose of this section, "customer's buried piping" does not include branch lines that serve yard lanterns, pool heaters, or other types of secondary equipment. Also, "maintain" means monitor for corrosion according to § 192.465 if the customer's buried piping is metallic, survey for leaks according to § 192.723, and if an unsafe condition is found, shut off the flow of gas, advise the customer of the need to repair the unsafe condition, or repair the unsafe condition.
- (b) Each operator shall notify each customer once in writing of the following information:
 - (1) The operator does not maintain the customer's buried piping.
 - (2) If the customer's buried piping is not maintained, it may be subject to the potential hazards of corrosion and leakage.
 - (3) Buried gas piping should be-
 - (i) Periodically inspected for leaks;
 - (ii) Periodically inspected for corrosion if the buried piping is metallic; and
 - (iii) Repaired if any unsafe condition is discovered.
 - (4) When excavating near buried gas piping, the piping should be located in advance, and the excavation done by hand.
 - (5) The operator (if applicable), plumbing contractors, and heating contractors can assist in locating, inspecting, and repairing the customer's buried piping.
- (c) Each operator shall notify each customer not later than August 14, 1996, or 90 days after the customer first receives gas at a particular location, whichever is later. However, operators of master meter systems may continuously post a general notice in a prominent location frequented by customers.
- (d) Each operator must make the following records available for inspection by the Administrator or a State agency participating under 49 U.S.C. 60105 or 60106:
 - (1) A copy of the notice currently in use; and
 - (2) Evidence that notices have been sent to customers within the previous 3 years.

§ 192.17 Filing of Operation, Inspection, and Maintenance Plan

Each operator shall file with the Pipeline Safety Office of the Arkansas Public Service Commission (PSO) a plan for operation, inspection, and maintenance of each pipeline facility which the operator owns or operates. In addition, each change to this plan must be filed with the PSO within 20 days after the change is made. Once filed, this plan becomes a part of these standards as though incorporated and must be followed by the operator.

§ 192.18 How to Notify PHMSA

- (a) An operator must provide any notification required by this part by -
 - (1) Sending the notification by electronic mail to:
InformationResourcesManager@dot.gov; or

- (2) Sending the notification by mail to ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd Floor, E22-321, 1200 New Jersey Ave. SE, Washington, DC 20590.
- (b) An operator must also notify the appropriate State or local pipeline safety authority when an applicable pipeline segment is located in a State where OPS has an interstate agent agreement, or an intrastate applicable pipeline segment is regulated by that State.
- (c) Unless otherwise specified, if an operator submits, pursuant to § 192.8, § 192.9, §192.13, §192.179, § 192.319, § 192.461, § 192.506, § 192.607, , §192.619, § 192.624§ 192.632, §192.634, § 192.636, § 192.710, § 192.712, § 192.714, § 192.745, §192.917, § 192.921,§192.927, § 192.933, or § 192.937a notification for use of a different integrity assessment method, analytical method, compliance period, sampling approach, pipeline material, or technique (*i.e.*, “other technology”) or “alternative equivalent technology”) than otherwise prescribed in those sections, that notification must be submitted to PHMSA for review at least 90 days in advance of using the other method, approach, compliance timeline, or technique. An operator may proceed to use the other method, approach, compliance timeline, or technique 91 days after submitting the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing the operator that PHMSA objects to the proposal or that PHMSA requires additional time and/or more information to conduct its review.

SUBPART B - MATERIALS

§ 192.51 Scope

This subpart prescribes minimum requirements for the selection and qualification of pipe and components for use in pipelines.

§ 192.53 General

Materials for pipe and components must be:

- (a) Able to maintain the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated;
- (b) Chemically compatible with any gas that they transport and with any other material in the pipeline with which they are in contact; and
- (c) Qualified in accordance with the applicable requirements of this subpart.

§ 192.55 Steel Pipe

- (a) New steel pipe is qualified for use under this part if:
 - (1) It was manufactured in accordance with a listed specification;
 - (2) It meets the requirements of:
 - (i) Section II of Appendix B to this part; or
 - (ii) If it was manufactured before November 12, 1970, either Section II or III of Appendix B to this part; or
 - (3) It is used in accordance with paragraph (c) or (d) of this section.
- (b) Used steel pipe is qualified for use under this part if:
 - (1) It was manufactured in accordance with a listed specification, and it meets the

- requirements of paragraph II-C of Appendix B to this part;
- (2) It meets the requirements of:
 - (i) Section II of Appendix B to this part; or
 - (ii) It was manufactured before November 12, 1970, either Section II or III of Appendix B to this part; or
 - (3) It has been used in an existing line of the same or higher pressure and meets the requirements of paragraph II-C of Appendix B to this part; or
 - (4) It is used in accordance with paragraph (c) of this section.
- (c) New or used steel pipe may be used at a pressure resulting in a hoop stress of less than 6,000 p.s.i. (41 MPa) where no close coiling or close bending is to be done, if visual examination indicates that the pipe is in good condition and that it is free of split seams and other defects that would cause leakage. If it is to be welded, steel pipe that has not been manufactured to a listed specification must also pass the weldability tests prescribed in paragraph II-B of Appendix B to this part.
- (d) Steel pipe that has not been previously used may be used as replacement pipe in a segment of pipeline if it has been manufactured prior to November 12, 1970, in accordance with the same specification as the pipe used in constructing that segment of pipeline.
- (e) New steel pipe that has been cold expanded must comply with the mandatory provisions of API Spec 5L (incorporated by reference, see § 192.7).

§ 192.57 [Removed and Reserved]

§ 192.59 Plastic Pipe

- (a) New plastic pipe is qualified for use under this part if:
 - (1) It is manufactured in accordance with a listed specification;
 - (2) It is resistant to chemicals with which contact may be anticipated; and
 - (3) It is free of visible defects.
- (b) Used plastic pipe is qualified for use under this part if:
 - (1) It was manufactured in accordance with a listed specification;
 - (2) It is resistant to chemicals with which contact may be anticipated;
 - (3) It has been used only in gas service;
 - (4) Its dimensions are still within the tolerances of the specification to which it was manufactured; and
 - (5) It is free of visible defects.
- (c) For the purpose of paragraphs (a)(1) and (b)(1) of this section, when a pipe of a diameter included in a listed specification is impractical to use, pipe of a diameter between the sizes included in a listed specification may be used if it:
 - (1) Meets the strength and design criteria required of pipe included in the listed specification; and
 - (2) Is manufactured from plastic compounds which meet the criteria for material required of pipe included in that listed specification.
- (d) Rework and/or regrind material is not allowed in plastic pipe produced after March 6, 2015,

used under this part.

§ 192.61 [Removed and Reserved]

§ 192.63 Marking of Materials

- (a) Except as provided in paragraph (d) and (e) of this section, each valve, fitting, length of pipe, and other component must be marked as prescribed in the specification or standard to which it was manufactured.
- (b) Surfaces of pipe and components that are subject to stress from internal pressure may not be field die stamped.
- (c) If any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations.
- (d) Paragraph (a) of this section does not apply to items manufactured before November 12, 1970, that meet all of the following:
 - (1) The item is identifiable as to type, manufacturer, and model.
 - (2) Specifications or standards giving pressure, temperature, and other appropriate criteria for the use of items are readily available.
- (e) All plastic pipe and components must also meet the following requirements:
 - (1) All markings on plastic pipe prescribed in the listed specification and the requirements of paragraph(e)(2) of this section must be repeated at intervals not exceeding two feet.
 - (2) Plastic pipe and components manufactured after December 31, 2019, must be marked in accordance with the listed specification.
 - (3) All physical markings on plastic pipelines prescribed in the listed specification and paragraph(e)(2) of this section must be legible until the time of installation.
- (f) Operators shall reidentify pipe if specification markings are obliterated during the coating and/or wrapping process. This reidentification is not necessary if pipe is immediately installed in a system.

§ 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 install pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by railroad unless the transportation is performed by API RP 5L1 (incorporated by reference, see § 192.7).
- (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 RP 5LW (incorporated by reference, see § 192.7).
- (c) *Truck.* 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 truck unless the transportation is performed in accordance with API RP 5LT (incorporated by reference, see § 192.7).

§192.67 Records: Material properties.

- (a) For steel transmission pipelines installed after July 1, 2020, an operator must collect or

make, and retain for the life of the pipeline, records that document the physical characteristics of the pipeline, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition of materials for pipe in accordance with §§192.53 and 192.55. Records must include tests, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed.

- (b) For steel transmission pipelines installed on or before July 1, 2020, if operators have records that document tests, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition in accordance with §§192.53 and 192.55, operators must retain such records for the life of the pipeline.
- (c) For steel transmission pipeline segments installed on or before July 1, 2020, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of §192.624 according to the terms of that section.

§192.69 Storage and Handling of Plastic Pipe and Associated Components.

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

SUBPART C - PIPE DESIGN

§ 192.101 Scope

This subpart prescribes the minimum requirements for the design of pipe.

§ 192.103 General

Pipe must be designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipe after installation.

§ 192.105 Design Formula for Steel Pipe

- (a) The design pressure for steel pipe is determined in accordance with the following formula:

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

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

S = Yield strength in pounds per square inch (kPa) determined in accordance with § 192.107.

D = Nominal outside diameter of the pipe in inches (millimeters).

T = Nominal wall thickness of the pipe in inches (millimeters). If this is unknown, it is determined in accordance with § 192.109. Additional wall thickness required for concurrent external loads in accordance with § 192.103 may not be included in computing design pressure.

F = Design factor determined in accordance with § 192.111.

E = Longitudinal joint factor determined in accordance with § 192.113.

T = Temperature derating factor determined in accordance with § 192.115.

- (b) If steel pipe that has been subjected to cold expansion to meet the SMYS is subsequently heated, other than by welding or stress relieving as a part of welding, the design pressure is limited to 75 percent of the pressure determined under paragraph (a) of this section if the temperature of the pipe exceeds 900°F (482°C) at any time or is held above 600°F (316°C) for more than 1 hour.

§ 192.107 Yield Strength (S) for Steel Pipe

- (a) For pipe that is manufactured in accordance with a specification listed in Section I of Appendix B of this part, the yield strength to be used in the design formula in § 192.105 is the SMYS stated in the listed specification, if that value is known.
- (b) For pipe that is manufactured in accordance with a specification not listed in Section I of Appendix B to this part or whose specification or tensile properties are unknown, the yield strength to be used in the design formula in § 192.105 is one of the following:
 - (1) If the pipe is tensile tested in accordance with Section II-D of Appendix B to this part, the lower of the following:
 - (i) 80 percent of the average yield strength determined by the tensile tests.
 - (ii) The lowest yield strength determined by the tensile tests, but not more than 52,000 p.s.i.
 - (2) If the pipe is not tensile tested as provided in Subparagraph (b)(1) of this paragraph, 24,000 p.s.i. (165 MPa).

§ 192.109 Nominal Wall Thickness (t) for Steel Pipe

- (a) If the nominal wall thickness for steel pipe is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end.
- (b) However, if the pipe is of uniform grade, size, and thickness and there are more than 10 lengths, only 10 percent of the individual lengths, but not less than 10 lengths, need be measured. The thickness of the lengths that are not measured must be verified by applying a gauge set to the minimum thickness found by the measurement. The nominal wall thickness to be used in the design formula in § 192.105 is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness used may not be more than 1.14 times the smallest measurement taken on pipe less than 20 inches (508 millimeters) in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe 20 inches (508 millimeters) or more in outside diameter.

§ 192.111 Design Factor (F) for Steel Pipe

- (a) Except as otherwise provided in paragraphs (b), (c), and (d) of this section, the design factor to be used in the design formula in § 192.105 is determined in accordance with the following table:

Class	Design
<u>Location</u>	<u>Factor</u>
(F) 1	0.72
2.....	0.60
3.....	0.50
4.....	0.40

- (b) A design factor of 0.60 or less must be used in the design formula in § 192.105 for steel pipe in Class 1 locations that:
 - (1) Crosses the right-of-way of an unimproved public road, without a casing;
 - (2) Crosses without a casing, or makes a parallel encroachment on, the right-of-way of either a hard surfaced road, a highway, a public street, or a railroad;
 - (3) Is supported by a vehicular, pedestrian, railroad, or pipeline bridge; or
 - (4) Is used in a fabricated assembly, (including separators, mainline valve assemblies, cross-connections, and river crossing headers) or is used within five pipe diameters in any direction from the last fitting of a fabricated assembly, other than a transition piece or an elbow used in place of a pipe bend which is not associated with a fabricated assembly.
- (c) For Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in § 192.105 for uncased steel pipe that crosses the right-of-way of a hard surfaced road, a highway, a public street, or a railroad.
- (d) For Class 1 or Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in § 192.105 for each compressor station, regulator station, and measuring station.

§ 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 the steel pipe	(1) The plate, skelp, or coil used for the pipe must be micro-alloyed, fine grain, fully killed, continuously cast steel with calcium treatment. (2) The carbon equivalents of the steel used for pipe must not exceed 0.25 percent by weight, as calculated by the Ito-Bessyo formula (Pcm formula) or 0.43 percent by weight, as calculated by the International Institute of Welding (IIW) formula. (3) The ratio of the specified outside diameter of the pipe to the specified wall thickness must be less than 100. The wall thickness or other mitigative measures must prevent denting and ovality anomalies during construction strength testing and anticipated operational stresses. (4) The pipe must be manufactured using API Spec 5L, product specification level 2 (incorporated by reference, see §192.7) for maximum operating pressures and minimum and maximum operating temperatures and other requirements under this section.
(b) Fracture control	(1) The toughness properties for pipe must address the potential for initiation, propagation and arrest of fractures in accordance with:

<p>(c) Plate/coil quality control</p>	<p>(i) API Spec 5L (incorporated by reference, see §192.7); or</p> <p>(ii) ASME B31.8 (incorporated by reference see §192.7); and</p> <p>(iii) Any correction factors needed to address pipe grades, pressures, temperatures, or gas compositions not expressly addressed in API Spec 5L, product specification level 2 or ASME B31.8 (incorporated by reference, see §192.7).</p> <p>(2) Fracture control must:</p> <p>(i) Ensure resistance to fracture initiation while addressing the full range of operating temperatures, pressures, gas compositions, pipe grade and operating stress levels, including maximum pressures and minimum temperatures for shut-in conditions, that the pipeline is expected to experience. If these parameters change during operation of the pipeline such that they are outside the bounds of what was considered in the design evaluation, the evaluation must be reviewed and updated to assure continued resistance to fracture initiation over the operating life of the pipeline.</p> <p>(ii) Address adjustments to toughness of pipe for each grade used and the decompression behavior of the gas at operating parameters;</p> <p>(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</p> <p>(iv) Include fracture toughness testing that is equivalent to that described in supplementary requirements SR5A, SR5B, and SR6 of API Spec 5L (incorporated by reference, see §192.7) and ensures ductile fracture and arrest with the following exceptions:</p> <p>(A) The results of the Charpy impact test prescribed in SR5A must indicate at least 80 percent average shear for any single test on each heat of steel.</p> <p>(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.</p> <p>(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.</p> <p>(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.</p>
---------------------------------------	---

	<p>(2) A mill inspection program or internal quality management program must include paragraph (c)(2)(i) of this section and either paragraph (c)(2)(ii) or (iii) of this section.</p> <p>(i) An ultrasonic test of the ends and at least 35 percent of the surface of the plate/coil or pipe to identify imperfections that impair serviceability such as laminations, cracks, and inclusions. At least 95 percent of the lengths of pipe manufactured must be tested. For all pipelines designed after December 22, 2008, the test must be done in accordance with ASTM A578/A578M Level B, or API Spec 5L Paragraph 7.8.10 (incorporated by reference, see §192.7) or equivalent method, and either</p> <p>(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</p> <p>(iii) A quality assurance monitoring program implemented by the operator that includes audits of:</p> <ul style="list-style-type: none"> (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	<p>(1) There must be a quality assurance program for pipe seam welds to assure tensile strength provided in API Spec 5L (incorporated by reference, see §192.7) for appropriate grades.</p> <p>(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:</p> <p>(i) A cross section of the weld seam of one pipe from each heat plus one pipe from each welding line per day; and</p> <p>(ii) For each sample cross section, a minimum of 13 readings (three for each heat affected zone, three in the weld metal, and two in each section of pipe base metal).</p> <p>(3) All of the seams must be ultrasonically tested after cold expansion and mill hydrostatic testing.</p>
(e) Mill hydrostatic test	<p>(1) All pipe to be used in a new pipeline segment installed after October 1, 2015, must be hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 95 percent SMYS for 10 seconds.</p>

<p>(f) Coating</p>	<p>(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.</p> <p>(3) Pipe in operation on or after December 22, 2008, but before October 1, 1015, must have been 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 on internal test pressure and the allowance for end loading stresses imposed by the pipe mill hydrostatic testing equipment as allowed by "ANSI/API Spec 5L" (incorporated by reference, see §192.7).</p> <p>(1) The pipe must be protected against external corrosion by a non-shielding coating.</p> <p>(2) Coating on pipe used for trenchless installation must be non-shielding and resist abrasions and other damage possible during installation.</p> <p>(3) A quality assurance inspection and testing program for the coating must cover the surface quality of the bare pipe, surface cleanliness and chlorides, blast cleaning, application temperature control, adhesion, cathodic disbondment, moisture permeation, bending, coating thickness, holiday detection, and repair.</p>
<p>(g) Fittings and flanges</p>	<p>(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.</p> <p>(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.</p> <p>(3) Valves, flanges and fittings must be rated based upon the required specification rating class for the alternative MAOP.</p>
<p>(h) Compressor stations</p>	<p>(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.</p> <p>(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 conditioning 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</p>

	<p>a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.</p> <p>(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 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.</p>

§ 192.113 Longitudinal Joint Factor (E) for Steel Pipe

- (a) The longitudinal joint factor to be used in the design formula in § 192.105 is determined in accordance with the table 1 to this paragraph (a):

Longitudinal Specification	Pipe Class	Joint Factor
(E) ASTM A53/A53M	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded	0.60
ASTM A106/A106M (incorporated by reference, <i>see</i> § 192.7)	Seamless	1.00
ASTM A333/A333M (incorporated by reference <i>see</i> § 192.7)	Seamless	1.00
	Electric resistance welded	1.00
ASTM A381 (incorporated by reference <i>see</i> § 192.7)	Double submerged arc welded	1.00
ASTM A671 (incorporated by reference <i>see</i> § 192.7)	Electric fusion welded	1.00
ASTM A672 (incorporated by reference <i>see</i> § 192.7)	Electric fusion welded	1.00
ASTM A 691 (incorporated by reference <i>see</i> § 192.7)	Electric fusion welded	1.00
API Spec 5L (incorporated by reference <i>see</i> § 192.7)	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
	Furnace butt welded	0.60

Other	Pipe over 4 inches (102 millimeters)	0.80
Other	Pipe 4 inches (102 millimeters) or less	0.60

- (b) If the type of longitudinal joint cannot be determined, the joint factor to be used must not exceed that designated for "Other."

§ 192.115 Temperature Derating Factor (T) for Steel Pipe

The temperature derating factor to be used in the design formula in § 192.105 is determined as follows:

Gas Temperature in Degrees Fahrenheit (Celsius)	Temperature Derating Factor
250° F (121° C) or less	1.0
300° F (149° C)	0.967
350° F (177° C)	0.933
400° F (204° C)	0.900
450° F (232° C)	0.867

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

§ 192.117 [Removed and Reserved]

§ 192.119 [Removed and Reserved]

§ 192.121 Design of Plastic Pipe

- (a) *Design formula.* The design formulas for plastic pipe are determined in accordance with either of the following formulas:

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

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

P = Design pressure, gage, psi (kPa).

S = For thermoplastic pipe, the hydrostatic design basis (HDB) is determined in accordance with the listed specification at a temperature equal to 73°F (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-3/2012 (incorporated by reference, see § 192.7). For reinforced thermosetting plastic

pipe, 11,000 psig (75,842 kPa).

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 (ANSI) preferred number series 10.

DF = Design Factor, a maximum of 0.32 unless otherwise specified for a particular material in this section.

(b) General requirements for plastic pipe and components.

(1) Except as provided in paragraphs (c) through (f) of this section, the design pressure for plastic pipe may not exceed a gauge pressure of 100 psig (689 kPa) for pipe used in:

- (i) Distribution systems; or
- (ii) Transmission lines in Class 3 and 4 locations.

(2) Plastic pipe may not be used where operating temperatures of the pipe will be:

- (i) 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
- (ii) Above the temperature at which the HDB used in the design formula under this section is determined.

(3) Unless specified for a particular material in this section, the wall thickness of plastic pipe may not be less than 0.062 inches (1.57 millimeters).

(4) All plastic pipe must have a listed HDB in accordance with PPI TR 4/2012 (incorporated by reference, see §192.7).

(c) Polyethylene (PE) pipe requirements.

(1) For PE pipe produced after July 14, 2004, but before January 22, 2019, a design pressure of up to 125 psig may be used, provided:

- (i) The material designation code is PE2406 or PE3408.
- (ii) The pipe has a nominal size (Iron Pipe Size (IPS) or Copper Tubing Size (CTS)) of 12 inches or less (above nominal pipe size of 12 inches, the design pressure is limited to 100 psig); and
- (iii) The wall thickness is not less than 0.062 inches (1.57 millimeters).

(2) For PE pipe produced on or after January 22, 2019, a DF of 0.40 may be used in the design formula, provided:

- (i) The design pressure does not exceed 125 psig;
- (ii) The material designation code is PE2708 or PE4710;

- (iii) The pipe has a nominal size (IPS or CTS) of 24 inches or less; and
- (iv) The wall thickness for a given outside diameter is not less than that listed in Table 1 to this paragraph (c)(2)(iv):

Table 1 to paragraph (c)(2)(iv):

PE Pipe - Minimum Wall Thickness and SDR Values		
Pipe Size (inches)	Minimum Wall Thickness (inches)	Corresponding SDR (values)
½" CTS	0.090	7.0
½" IPS	0.090	9.3
¾" CTS	0.090	9.7
¾" IPS	0.095	11
1" CTS	0.099	11
1" IPS	0.119	11
1 ¼" CTS	0.121	11
1 ¼" IPS	0.151	11
1 ½" IPS	0.173	11
2"	0.216	11
3"	0.259	13.5
4"	0.265	17.0
6"	0.315	21
8"	0.411	21
10"	0.512	21
12"	0.607	21
16"	0.762	21
18"	0.857	21
20"	0.952	21
22"	1.048	21
24"	1.143	21

- (d) *Polyamide (PA-11) pipe requirements.*
- (1) For PA-11 pipe produced after January 23, 2009, but before January 22, 2019, a DF of 0.40 may be used in the design formula, provided:
 - (i) The design pressure does not exceed 200 psig;
 - (ii) The material designation code is PA32312 or PA32316;
 - (iii) The pipe has a nominal size (IPS or CTS) of 4 inches or less; and
 - (iv) The pipe has a standard dimension ratio of SDR - 11 or less (i.e., thicker wall pipe).
 - (2) For PA- 11 pipe produced on or after January 22, 2019, a DF of 0.40 may be used in the design formula, provided:
 - (i) The design pressure does not exceed 250 psig;
 - (ii) The material designation code is PA32316;
 - (iii) The pipe has a nominal size (IPS or CTS) of 6 inches or less; and

- (iv) The minimum wall thickness for a given outside diameter is not less than that listed in Table 2 to this paragraph (d)(2)(iv):

Table 2 to paragraph (d)(2)(iv):

PA-11 Pipe: Minimum Wall Thickness and SDR Values		
Pipe Size (inches)	Minimum Wall Thickness (inches)	Corresponding SDR (values)
½" CTS	0.090	7.0
½" IPS	0.090	9.3
¾" CTS	0.090	9.7
¾" IPS	0.095	11
1" CTS	0.099	11
1" IPS	0.119	11
1 ¼" CTS	0.121	11
1 ¼" IPS	0.151	11
1 ½" IPS	0.173	11
2" IPS	0.216	11
3" IPS	0.259	13.5
4" IPS	0.333	13.5
6" IPS	0.491	13.5

- (e) *Polyamide (PA- 12) pipe requirements.* For PA- 12 pipe produced after January 22, 2019, a DF of 0.40 may be used in the design formula, provided:
- (1) The design pressure does not exceed 250 psig;
 - (2) The material designation code is PA42316;
 - (3) The pipe has a nominal size (IPS or CTS) of 6 inches or less; and
 - (4) The minimum wall thickness for a given outside diameter is not less than that listed in Table 3 to this Paragraph (e)(4):

Table 3 to Paragraph (e)(4):

PA-12 Pipe: minimum wall thickness and SDR values		
Pipe Size (inches)	Minimum Wall Thickness (inches)	Corresponding dimension ratio (values)
½" CTS	0.090	7.0
½" IPS	0.090	9.3
¾" CTS	0.090	9.7
¾" IPS	0.095	11

1" CTS	0.099	11
1" IPS	0.119	11
1 ¼" IPS	0.151	11
1 ½" IPS	0.173	11
2" IPS	0.216	11
3" IPS	0.259	13.5
4" IPS	0.333	13.5
6" IPS	0.491	13.5

(f) *Reinforced thermosetting plastic pipe requirements.*

- (1) Reinforced thermosetting plastic pipe may not be used at operating temperatures above 150 °F (66 °C).
- (2) 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 in 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)

§ 192.123 [Removed and Reserved]

§ 192.125 Design of Copper Pipe

- (a) Copper pipe used in mains must have a minimum wall thickness of 0.065 inches (1.65 millimeters) and must be hard drawn.
- (b) Copper pipe used in service lines must have wall thickness not less than that indicated in the following table:

Standard Size Inch (millimeter)	Nominal O.D. Inch (millimeter)	Wall Thickness, inch (millimeter)	
		Nominal	Tolerance
½ (13)	.625 (16)	.040 (1.06)	.0035 (.0889)
⅝ (16)	.750 (19)	.042 (1.07)	.0035 (.0889)
¾ (19)	.875 (22)	.045 (1.14)	.004 (.102)
1 (24)	1.125 (29)	.050 (1.27)	.004 (.102)
1 ¼ (32)	1.375 (35)	.055 (1.40)	.0045 (.1143)
1 ½ (38)	1.625 (41)	.060 (1.52)	.0045 (.1143)

- (c) Copper pipe used in mains and service line may not be used at pressures in excess of 100 p.s.i. (689 kPa) gage.
- (d) Copper pipe that does not have an internal corrosion resistant lining may not be used to carry gas that has an average hydrogen sulfide content of more than 0.3 grains/100 ft.³

(6.9/m³) under standard conditions. Standard conditions refers to 60°F and 14.7 p.s.i.a. (15.6°C and one atmosphere).

§ 192.127 Records: Pipe Design

- (a) For steel transmission pipelines installed after July 1, 2020], an operator must collect or make, and retain for the life of the pipeline, records documenting that the pipe is designed to withstand anticipated external pressures and loads in accordance with § 192.103 and documenting that the determination of design pressure for the pipe is made in accordance with § 192.105.
- (b) For steel transmission pipelines installed on or before July 1, 2020, if operators have records documenting pipe design and the determination of design pressure in accordance with §§ 192.103 and 192.105, operators must retain such records for the life of the pipeline.
- (c) For steel transmission pipeline segments installed on or before July 1, 2020, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of § 192.624 according to the terms of that section.

SUBPART D - DESIGN OF PIPELINE COMPONENTS

§ 192.141 Scope

This subpart prescribes minimum requirements for the design and installation of pipeline components and facilities. In addition, it prescribes requirements relating to protection against accidental over pressuring.

§ 192.143 General Requirements

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

§ 192.144 Qualifying Metallic Components

Notwithstanding any requirement of this subpart which incorporates by reference an edition of a document listed in § 192.7 or Appendix B of this part, a metallic component manufactured in accordance with any other edition of that document is qualified for use under this part if-

- (a) It can be shown through visual inspection of the cleaned component that no defect exists which might impair the strength or tightness of the component; and

- (b) The edition of the document under which the component was manufactured has equal or more stringent requirements for the following as an edition of that document currently or previously listed in § 192.7 or Appendix B of this part:
 - (1) Pressure testing;
 - (2) Materials; and
 - (3) Pressure and temperature ratings.

§ 192.145 Valves

- (a) Except for cast iron and plastic valves, each valve must meet the minimum requirements of API Spec 6D (incorporated by reference, see § 192.7), or to a national or international standard that provides an equivalent performance level. A valve may not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those requirements.
- (b) Each cast iron and plastic valve must comply with the following:
 - (1) The valve must have a maximum service pressure rating for temperatures that equal or exceed the maximum service temperature; and
 - (2) The valve must be tested as part of the manufacturing, as follows:
 - (i) With the valve in the fully open position, the shell must be tested with no leakage to a pressure at least 1.5 times the maximum service rating.
 - (ii) After the shell test, the seat must be tested to a pressure not less than 1.5 times the maximum service pressure rating. Except for swing check valves, test pressure during the seat test must be applied successively on each side of the closed valve with the opposite side open. No visible leakage is permitted.
 - (iii) After the last pressure test is completed, the valve must be operated through its full travel to demonstrate freedom from interference.
- (c) Each valve must be able to meet the anticipated operating conditions.
- (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.
- (f) Except for excess flow valves, plastic valves installed after January 22, 2019, must meet the minimum requirements of a listed specification. A valve may not be used under operating conditions that exceed the applicable pressure and temperature ratings contained in the listed specification.

§ 192.147 Flanges and Flange Accessories

- (a) Each flange or flange accessory (other than cast iron) must meet the minimum requirements of ASME/ANSI B16.5 (incorporated by reference, see § 192.7), ANSI/MSS SP-44 (incorporated by reference, see § 192.7), or the equivalent.
- (b) Each flange assembly must be able to withstand the maximum pressure at which the pipeline is to be operated and to maintain its physical and chemical properties at any temperature to which it is anticipated that it might be subjected in service.
- (c) Each flange on a flanged joint in cast iron pipe must conform in dimensions, drilling, face and gasket design to ASME/ANSI B16.1 (incorporated by reference, see § 192.7) and be cast integrally with the pipe, valve, or fitting.

§ 192.149 Standard Fittings

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

§ 192.150 Passage of Internal Inspection Devices

- (a) Except as provided in paragraphs (b) and (c) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must be designed and constructed to accommodate the passage of instrumented internal inspection devices in accordance with NACE SP0102, section 7 (incorporated by reference, see § 192.7).
- (b) This section does not apply to:
 - (1) Manifolds;
 - (2) Station piping such as at compressor stations, meter stations, or regulator stations;
 - (3) Piping associated with storage facilities, other than a continuous run of transmission line between a compressor station and storage facilities;
 - (4) Cross-overs;
 - (5) Sizes of pipe for which an instrumented internal inspection device is not commercially available;
 - (6) Transmission lines, operated in conjunction with a distribution system which are installed in Class 4 locations;
 - (7) Gathering lines; and
 - (8) Other piping that, under § 190.9 of this chapter, the Administrator finds in a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices.
- (c) An operator encountering emergencies, construction time constraints or other unforeseen construction problems need not construct a new or replacement segment of a

transmission line to meet subparagraph (a) of this paragraph, if the operator determines and documents why impracticability prohibits compliance with subparagraph (a) of this paragraph. Within 30 days after discovering the emergency or construction problem the operator must petition, under § 190.9 of this chapter, for approval that design and construction to accommodate passage of instrumented internal inspection devices would be impracticable. If the petition is denied, within 1 year after the date of the notice of denial, the operator must modify that segment to allow passage of instrumented internal inspection devices.

§ 192.151 Tapping

- (a) Each mechanical fitting used to make a hot tap must be designed for at least the operating pressure of the pipeline.
- (b) Where a ductile iron pipe is tapped, the extent of full-thread engagement and the need for the use of outside-sealing service connections, tapping saddles, or other fixtures must be determined by service conditions.
- (c) Where a threaded tap is made in cast iron or ductile iron pipe, the diameter of the tapped hole may not be more than 25 percent of the nominal diameter of the pipe unless the pipe is reinforced, except that:
 - (1) Existing taps may be used for replacement service, if they are free of cracks and have good threads; and
 - (2) A 1 1/4 inch (32 millimeters) tap may be made in a 4 inch (102 millimeters) cast iron or ductile iron pipe, without reinforcement. However, in areas where climate, soil, and service conditions may create unusual external stresses on cast iron pipe, unreinforced taps may be used only on 6 inch (152 millimeters) or larger pipe.

§ 192.153 Components Fabricated by Welding

- (a) Except for branch connections and assemblies of standard pipe and fittings joined by circumferential welds, the design pressure of each component fabricated by welding, whose strength cannot be determined, must be established in accordance with paragraph UG-101 of the ASME Boiler and Pressure Vessel Code (BPVC) (Section VIII, Division 1) (incorporated by reference, see § 192.7).
- (b) Each prefabricated unit that uses plate and longitudinal seams must be designed, constructed, and tested in accordance with section 1 of the ASME BPVC (*Rules for Construction of Pressure Vessels* as defined in either Section VIII, Division 1 or Section VIII, Division 2; incorporated by reference, see §192.7), except for the following:
 - (1) Regularly manufactured butt-welding fittings.
 - (2) Pipe that has been produced and tested under a specification listed in Appendix B to this part.
 - (3) Partial assemblies such as split rings or collars.
 - (4) Prefabricated units that the manufacturer certifies have been tested to at least twice the maximum pressure to which they will be subjected under the anticipated operating conditions.
- (c) Orange-peel bull plugs and orange-peel swages may not be used on pipelines that are to operate at a hoop stress of 20 percent or more of the SMYS of the pipe.
- (d) Except for flat closures designed in accordance with the ASME BPVC, (Section VIII,

Division 1 or Division 2), (both incorporated by reference, see § 192.7) flat closures and fish tails may not be used on pipe that either operates at 100 p.s.i. (689 kilopascals) or more, or that is more than 3 inches (76 millimeters) nominal diameter.

- (e) The test requirements for a prefabricate unit or pressure vessel, defined for this paragraph as components with a design pressure established in accordance with paragraph (a) or paragraph (b) of this section are as follows.
 - (1) A prefabricated unit or pressure vessel installed after July 14, 2004 is not subject to the strength testing requirements at §192.505(b) provided the component has been tested in accordance with paragraph (a) or paragraph (b) of this section and with a test factor of at least 1.3 times MAOP.
 - (2) A prefabricated unit or pressure vessel must be tested for a duration specified as follows.
 - (i) A prefabricated unit or pressure vessel installed after July 14, 2004, but before October 1, 2021 is exempt from §§ 192.505(c) and (d) and 192.507(c) provided it has been tested for a duration consistent with the ASME BPVC requirements referenced in paragraph (a) or (b) of this section.
 - (ii) A prefabricated unit or pressure vessel installed on or after October 1, 2021 must be tested for the duration specified in either § 192.505(c) or (d), § 192.507(c), or § 192.509(a), whichever is applicable for the pipeline in which the component is being installed.
 - (3) For any prefabricated unit or pressure vessel permanently or temporarily installed on a pipeline facility, an operator must either:
 - (i) Test the prefabricated unit or pressure vessel in accordance with this section and Subpart J of this part after it has been placed on its support structure at its final installation location. The test may be performed before or after it has been tied-in to the pipeline. Test records that meet § 192.517(a) must be kept for the operational life of the prefabricated unit or pressure vessel; or
 - (ii) For a prefabricated unit or pressure vessel that is pressure tested prior to installation or where a manufacturer's pressure test is used in accordance with paragraph (e) of this section, inspect the prefabricated unit or pressure vessel after it has been placed on its support structure at its final installation location and confirm that the prefabricated unit or pressure vessel was not damaged during any prior operation, transportation, or installation into the pipeline. The inspection procedure and documented inspection must include visual inspection for vessel damage, including, at a minimum, inlets, outlets, and lifting locations. Injurious defects that are an integrity threat may include dents, gouges, bending, corrosion, and cracking. This inspection must be performed prior to operation but may be performed either before or after it has been tied-in to the pipeline. If injurious defects that are an integrity threat are found, the prefabricated unit or pressure vessel must be either non-destructively tested, re-pressure tested, or remediated in accordance with applicable part 192 requirements for a fabricated unit or with the applicable ASME BPVC requirements referenced in paragraphs (a) or (b) of this section. Test, inspection, and repair records for the fabricated unit or pressure vessel must be kept for the operational life of the component. Test records must meet the requirements in §192.517(a).

- (4) An initial pressure test from the prefabricated unit or pressure vessel manufacturer may be used to meet the requirements of this section with the following conditions:
 - (i) The prefabricated unit or pressure vessel is newly-manufactured and installed on or after October 1, 2021, except as provided in paragraph (e)(4)(ii) of this section.
 - (ii) An initial pressure test from the fabricated unit or pressure vessel manufacturer or other prior test of a new or existing prefabricated unit or pressure vessel may be used for a component that is temporarily installed in a pipeline facility in order to complete a testing, integrity assessment, repair, odorization, or emergency response-related task, including noise or pollution abatement. The temporary component must be promptly removed after that task is completed. If operational and environmental constraints require leaving a temporary prefabricated unit or pressure vessel under this paragraph in place for longer than 30 days, the operator must notify PHMSA and State or local pipeline safety authorities, as applicable, in accordance with §192.18.
 - (iii) The manufacturer's pressure test must meet the minimum requirements of this part; and
 - (iv) The operator inspects and remediates the prefabricated unit or pressure vessel after installation in accordance with paragraph (e)(3)(ii) of this section.
- (5) An existing prefabricated unit or pressure vessel that is temporarily removed from a pipeline facility to complete a testing, integrity assessment, repair, odorization, or emergency response-related task, including noise or pollution abatement, and then re-installed at the same location must be inspected in accordance with paragraph (e)(3)(ii) of this section; however, a new pressure test is not required provided no damage or threats to the operational integrity of the prefabricated unit or pressure vessel were identified during the inspection and the MAOP of the pipeline is not increased.
- (6) Except as provided in paragraphs (e)(4)(ii) and (5) of this section, on or after October 1, 2021, an existing prefabricated unit or pressure vessel relocated and operated at a different location must meet the requirements of this part and the following:
 - (i) The prefabricated unit or pressure vessel must be designed and constructed in accordance with the requirements of this part at the time the vessel is returned to operational service at the new location; and
 - (ii) The prefabricated unit or pressure vessel must be pressure tested by the operator in accordance with the testing and inspection requirements of this part applicable to newly installed prefabricated units and pressure vessels.

§ 192.155 Welded Branch Connections

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

§ 192.157 Extruded Outlets

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

§ 192.159 Flexibility

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

§ 192.161 Supports and Anchors

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

§ 192.163 Compressor Stations: Design and Construction

- (a) *Location of compressor building.* Each main compressor building of a compressor station must be located on property under the control of the operator. It must be far enough away from adjacent property, not under control of the operator, to minimize the possibility of fire being communicated to the compressor building from structures on adjacent property. There must be enough open space around the main compressor building to allow the free

movement of fire-fighting equipment.

- (b) *Building construction.* Each building on a compressor station site must be made of noncombustible materials if it contains either:
 - (1) Pipe more than 2 inches (51 millimeters) in diameter that is carrying gas under pressure; or
 - (2) Gas handling equipment other than gas utilization equipment used for domestic purposes.
- (c) *Exits.* Each operating floor of a main compressor building must have at least two separated and unobstructed exits located so as to provide a convenient possibility of escape and an unobstructed passage to a place of safety. Each door latch on an exit must be of a type which can be readily opened from the inside without a key. Each swinging door located in an exterior wall must be mounted to swing outward.
- (d) *Fenced areas.* Each fence around a compressor station must have at least two gates located so as to provide a convenient opportunity for escape to a place of safety or have other facilities affording a similarly convenient exit from the area. Each gate located within 200 feet (61 meters) of any compressor plant building must open outward and, when occupied, must be openable from the inside without a key.
- (e) *Electrical facilities.* Electrical equipment and wiring installed in compressor stations must conform to the NFPA-70 (incorporated by reference, see § 192.7), so far as that code is applicable.

§ 192.165 Compressor Stations: Liquid Removal

- (a) Where entrained vapors in gas may liquefy under the anticipated pressure and temperature conditions, the compressor must be protected against the introduction of those liquids in quantities that could cause damage.
- (b) Each liquid separator used to remove entrained liquids at a compressor station must:
 - (1) Have a manually operable means of removing these liquids;
 - (2) Where slugs of liquid could be carried into the compressors, have either automatic liquid removal facilities, an automatic compressor shut-down device, or a high liquid level alarm; and
 - (3) Be manufactured in accordance with Section VIII ASME Boiler and Pressure Vessel Code (BPVC) (incorporated by reference, see § 192.7) and the additional requirements of § 192.153(e), except that liquid separators constructed of pipe and fittings without internal welding must be fabricated with a design factor of 0.4 or less.

§ 192.167 Compressor Station: Emergency ShutDown

- (a) Except for unattended field compressor stations of 1,000 horsepower (746 kilowatts) or less, each compressor station must have an emergency shutdown system that meets the following:
 - (1) It must be able to block gas out of the station and blow down the station piping.
 - (2) It must discharge gas from the blowdown piping at a location where the gas will not create a hazard.
 - (3) It must provide means for the shutdown of gas compressing equipment, gas fires, and electrical facilities in the vicinity of gas headers and in the compressor building

except, that:

- (i) Electrical circuits that supply emergency lighting required to assist station personnel in evacuating the compressor building and the area in the vicinity of the gas headers must remain energized; and
 - (ii) Electrical circuits needed to protect equipment from damage may remain energized.
- (4) It must be operable from at least two locations, each of which is:
- (i) Outside the gas area of the station;
 - (ii) Near the exit gates, if the station is fenced, or near emergency exits, if not fenced; and
 - (iii) Not more than 500 feet (153 meters) from the limits of the station.
- (b) If a compressor station supplies gas directly to a distribution system with no other adequate source of gas available, the emergency shutdown system must be designed so that it will not function at the wrong time and cause the unintended outage on the distribution system.

§ 192.169 Compressor Stations: Pressure Limiting Devices

- (a) Each compressor station must have pressure relief or other suitable protective devices of sufficient capacity and sensitivity to ensure that the maximum allowable operating pressure of the station piping and equipment is not exceeded by more than 10 percent.
- (b) Each vent line that exhausts gas from the pressure relief valves of a compressor station must extend to a location where the gas may be discharged without hazard.

§ 192.171 Compressor Stations: Additional Safety Equipment

- (a) Each compressor station must have adequate fire protection facilities. If fire pumps are a part of these facilities, their operation may not be affected by the emergency shutdown system.
- (b) Each compressor station prime mover, other than an electrical induction or synchronous motor, must have an automatic device to shut down the unit before the speed of either the prime mover or the driven unit exceeds a maximum safe speed.
- (c) Each compressor unit in a compressor station must have a shutdown or alarm device that operates in the event of inadequate cooling or lubrication of the unit.
- (d) Each compressor station gas engine that operates with pressure gas injection must be equipped so that the stoppage of the engine automatically shuts off the fuel and vents the engine distribution manifold.
- (e) Each muffler for a gas engine in a compressor station must have vent slots or holes in baffles of each compartment to prevent gas from being trapped in the muffler.

§ 192.173 Compressor Stations: Ventilation

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

§ 192.175 Pipe-Type and Bottle-Type Holders

- (a) Each pipe-type and bottle-type holder must be designed so as to prevent the accumulation of liquids in the holder, in connecting pipe, or in auxiliary equipment, that might cause

corrosion or interfere with the safe operation of the holder.

- (b) Each pipe-type or bottle-type holder must have minimum clearance from other holders in accordance with the following formula:

$$C = (3D \times P \times F)/1000 \text{ in inches; } (C = (3D \times P \times F)/6,895) \text{ in millimeters}$$

In which:

C = Minimum clearance between pipe containers or bottles in inches (millimeters).

D = Outside diameter of pipe containers or bottles in inches (millimeters) P = Maximum allowable operating pressure, psi (kPa) gauge.

F = Design factor as set forth in § 192.111 of this part.

§ 192.177 Additional Provisions for Bottle-Type Holders

- (a) Each bottle-type holder must be:
- (1) Located on a site entirely surrounded by fencing that prevents access by unauthorized persons and with minimum clearance from the fence as follows:

Maximum Allowable Operating Pressure	Minimum Clearance Feet (meters)
Less than 1,000 p.s.i. (7 MPa) gage	25 (7.6)
1,000 p.s.i. (7 MPa) or more	100 (31)

- (2) Designed using the design factors set forth in § 192.111; and
- (3) Buried with a minimum cover in accordance with § 192.327.
- (b) Each bottle-type holder manufactured from steel that is not weldable under field conditions must comply with the following:
- (1) A bottle-type holder made from alloy steel must meet the chemical and tensile requirements for the various grades of steel in ASTM A372/A372M (incorporated by reference, see § 192.7).
- (2) The actual yield-tensile ratio of the steel may not exceed 0.85.
- (3) Welding may not be performed on the holder after it has been heat treated or stress relieved, except that copper wires may be attached to the small diameter portion of the bottle end closure for cathodic protection if a localized thermite welding process is used.
- (4) The holder must be given a mill hydrostatic test at a pressure that produces a hoop stress at least equal to 85 percent of the SMYS.
- (5) The holder, connection pipe, and components must be leak tested after installation as required by Subpart J of this part.

§ 192.179 Transmission Line Valves

- (a) Each transmission line must have sectionalizing block valves spaced as follows, unless in a particular case the Administrator finds that alternative spacing would provide an equivalent level of safety:
 - (1) Each point on the pipeline in a Class 4 location must be within 2 1/2 miles (4 kilometers) of a valve.
 - (2) Each point on the pipeline in a Class 3 location must be within 4 miles (6.4 kilometers) of a valve.
 - (3) Each point on the pipeline in a Class 2 location must be within 7 1/2 miles (12 kilometers) of a valve.
 - (4) Each point on the pipeline in a Class 1 location must be within 10 miles (16 kilometers) of a valve.
- (b) Each sectionalizing block valve on a transmission line must comply with the following:
 - (1) The valve and the operating device to open or close the valve must be readily accessible and protected from tampering and damage.
 - (2) The valve must be supported to prevent settling of the valve or movement of the pipe to which it is attached.
- (c) Each section of transmission line between main line valves must have a blowdown valve with enough capacity to allow the transmission line to be blown down as rapidly as practicable. Each blowdown discharge must be located so the gas can be blown to the atmosphere without hazard and, if the transmission line is adjacent to an overhead electric line, so that the gas is directed away from the electrical conductors.
- (d) Offshore segments of transmission lines must be equipped with valves or other components to shut off the flow of gas to an offshore platform in an emergency.
- (e) For onshore transmission pipeline segments with diameters greater than or equal to 6 inches that are constructed after April 10, 2023, the operator must install rupture-mitigation valves (RMV) or an alternative equivalent technology whenever a valve must be installed to meet the appropriate valve spacing requirements of this section. An operator seeking to use alternative equivalent technology must notify PHMSA in accordance with the procedures set forth in paragraph (g) of this section. All RMVs and alternative equivalent technologies installed pursuant to this paragraph (e) must meet the requirements of § 192.636. The installation requirements in this paragraph (e) do not apply to pipe segments with a potential impact radius (PIR), as defined in § 192.903, that is less than or equal to 150 feet in either Class 1 or Class 2 locations. An operator may request an extension of the installation compliance deadline requirements of this paragraph (e) if it can demonstrate to PHMSA, in accordance with the notification procedures in § 192.18, that those installation compliance deadlines would be economically, technically, or operationally infeasible for a particular new pipeline.
- (f) For entirely replaced onshore transmission pipeline segments, as defined in § 192.3, with diameters greater than or equal to 6 inches and that are installed after April 10, 2023, the operator must install RMVs or an alternative equivalent technology whenever a valve must be installed to meet the appropriate valve spacing requirements of this section. An operator seeking to use alternative equivalent technology must notify PHMSA in

accordance with the procedures set forth in paragraph (g) of this section. All RMVs and alternative equivalent technologies installed pursuant to this paragraph (f) must meet the requirements of § 192.636. The requirements of this paragraph (f) apply when the applicable pipeline replacement project involves a valve, either through addition, replacement, or removal. The installation requirements in this paragraph (f) do not apply to pipe segments with a PIR, as defined in § 192.903, that is less than or equal to 150 feet in either Class 1 or Class 2 locations. An operator may request an extension of the installation compliance deadline requirements of this paragraph (f) if it can demonstrate to PHMSA, in accordance with the notification procedures in § 192.18, that those installation compliance deadlines would be economically, technically, or operationally infeasible for a particular pipeline replacement project.

- (g) If an operator elects to use alternative equivalent technology in accordance with paragraph (e) or (f) of this section, the operator must notify PHMSA in accordance with the procedures in § 192.18. The operator must include a technical and safety evaluation in its notice to PHMSA. Valves that are installed as alternative equivalent technology must comply with §§ 192.634 and 192.636. An operator requesting use of manual valves as an alternative equivalent technology must also include within the notification submitted to PHMSA a demonstration that installation of an RMV as otherwise required would be economically, technically, or operationally infeasible. An operator may use a manual compressor station valve at a continuously manned station as an alternative equivalent technology, and use of such valve would not require a notification to PHMSA in accordance with § 192.18, but it must comply with § 192.636.
- (h) The valve spacing requirements of paragraph (a) of this section do not apply to pipe replacements on a pipeline if the distance between each point on the pipeline and the nearest valve does not exceed:
 - (1) Four (4) miles in Class 4 locations, with a total spacing between valves no greater than 8 miles;
 - (2) Seven-and-a-half (7 1/2) miles in Class 3 locations, with a total spacing between valves no greater than 15 miles; or
 - (3) Ten (10) miles in Class 1 or 2 locations, with a total spacing between valves no greater than 20 miles.

§ 192.181 Distribution Line Valves

- (a) Each high-pressure distribution system must have valves spaced so as to reduce the time to shut down a section of main in an emergency. The valve spacing is determined by the operating pressure, the size of the mains, and the local physical conditions.
- (b) Each regulator station controlling the flow or pressure of gas in a distribution system must have a valve installed on the inlet piping at a distance from the regulator station sufficient to permit the operation of the valve during an emergency that might preclude access to the station.
- (c) Each valve on a main installed for operating or emergency purposes must comply with the following:
 - (1) The valve must be placed in a readily accessible location so as to facilitate its

operation in an emergency.

- (2) The operating stem or mechanism must be readily accessible.
- (3) If the valve is installed in a buried box or enclosure, the box or enclosure must be installed so as to avoid transmitting external loads to the main.

§ 192.183 Vaults: Structural Design Requirements

- (a) Each underground vault or pit for valves, pressure relieving, pressure limiting, or pressure regulating stations, must be able to meet the loads which may be imposed upon it, and to protect installed equipment.
- (b) There must be enough working space so that all of the equipment required in the vault or pit can be properly installed, operated, and maintained.
- (c) Each pipe entering, or within, a regulator vault or pit must be steel for sizes 10 inches (254 millimeters), and less, except that control and gauge piping may be copper. Where pipe extends through the vault or pit structure, provision must be made to prevent the passage of gasses or liquids through the opening and to avert strains in the pipe.

§ 192.185 Vaults: Accessibility

Each vault must be located in an accessible location and, so far as practical, away from:

- (a) Street intersections or points where traffic is heavy or dense;
- (b) Points of minimum elevation, catch basins, or places where the access cover will be in the course of surface waters; and
- (c) Water, electric, steam, or other facilities.

§ 192.187 Vaults: Sealing, Venting, and Ventilation

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

- (a) When the internal volume exceeds 200 cubic feet (5.7 cubic meters):
 - (1) The vault or pit must be ventilated with two ducts, each having at least the ventilating effect of a pipe 4 inches (102 millimeters) in diameter;
 - (2) The ventilation must be enough to minimize the formation of combustible atmosphere in the vault or pit; and
 - (3) The ducts must be high enough above grade to disperse any gas-air mixtures that might be discharged.
- (b) When the internal volume is more than 75 cubic feet (2.1 cubic meters) but less than 200 cubic feet (5.7 cubic meters):
 - (1) If the vault or pit is sealed, each opening must have a tight fitting cover without open holes through which an explosive mixture might be ignited, and there must be a means for testing the internal atmosphere before removing the cover;
 - (2) If the vault or pit is vented, there must be a means of preventing external sources of ignition from reaching the vault atmosphere; or
 - (3) If the vault or pit is ventilated, paragraph (a) or (c) of this section applies.
- (c) If a vault or pit covered by paragraph (b) of this section is ventilated by openings in the covers or gratings and the ratio of the internal volume, in cubic feet, to the effective ventilating area of the cover or grating, in square feet, is less than 20 to 1, no additional

ventilation is required.

§ 192.189 Vaults: Drainage and Waterproofing

- (a) Each vault must be designed so as to minimize the entrance of water.
- (b) A vault containing gas piping may not be connected by means of a drain connection to any other underground structure.
- (c) Electrical equipment in vaults must conform to the applicable requirements of Class 1, Group D, of the National Electrical Code, NFPA-70 (incorporated by reference see § 192.7).

§ 192.191 [Removed and Reserved]

§ 192.193 Valve Installation in Plastic Pipe

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

§ 192.195 Protection Against Accidental Overpressuring

- (a) *General requirements.* Except as provided in § 192.197, each pipeline that is connected to a gas source so that the maximum allowable operating pressure could be exceeded as the result of pressure control failure or of some other type of failure, must have pressure relieving or pressure limiting devices that meet the requirements of §§ 192.199 and 192.201.
- (b) *Additional requirements for distribution systems.* Each distribution system that is supplied from a source of gas that is at a higher pressure than the maximum allowable operating pressure for the system must:
 - (1) Have pressure regulation devices capable of meeting the pressure, load, and other service conditions that will be experienced in normal operation of the system, and that could be activated in the event of failure of some portion of the system; and
 - (2) Be designed so as to prevent accidental overpressuring.

§ 192.197 Control of Pressure of Gas Delivered from High-Pressure Distribution Systems

- (a) Each operator shall establish a maximum actual operating pressure for each distribution system as required by § 192.622.
- (b) If the maximum actual operating pressure of the distribution system is 60 p.s.i. (414 kPa) gage, or less, and a service regulator having the following characteristics is used, no other pressure limiting device is required:
 - (1) A regulator capable of reducing line pressure to pressures required to safely operate the customers' gas utilization equipment.
 - (2) A regulator with an internal relief valve vented to the outside atmosphere or an overpressure control device.

A single port valve with the orifice size commensurate with the inlet pressure to assure adequate volume and pressure to the customer and also assures the overpressure control device prevents the build-up of pressure that would cause the unsafe operation of the customers' gas utilization equipment.
 - (3) A valve seat made of resilient material designed to withstand abrasion of the gas,

- impurities in gas, cutting of the valve, and to resist permanent deformation when pressed against the valve port.
- (4) Pipe connections to the regulator not exceeding 2 inches (51 millimeters) in diameter.
 - (5) A regulator that, under normal operating conditions, will regulate the downstream pressure within the necessary limits of accuracy and prevents the build-up of pressure under no flow conditions that would cause the unsafe operation of the customers' gas utilization equipment.
 - (6) A self-contained regulator with no external static or control lines.
- (c) If the maximum actual operating pressure of the distribution system is 60 p.s.i. (414 kPa) gage, or less, and a regulator that does not have all the characteristics listed in paragraph (b) of this section is used, or if the gas contains materials that seriously affects the operation of the regulator, there must be suitable protective devices installed to prevent over-pressuring the customers' gas utilization equipment if the regulator fails.
- (d) If the maximum actual operating pressure of the distribution system exceeds 60 p.s.i. (414 kPa) gage, one of the following methods must be used to regulate and limit to a safe value, the pressure delivered to the customers' gas utilization equipment:
- (1) A service regulator having the characteristics listed in paragraph (b) this part, and another regulator located upstream from the service regulator. The upstream regulator may not be set to maintain a pressure higher than 60 p.s.i. (414 kPa) gage. If the upstream regulator does not have an internal relief valve of sufficient capacity to limit the pressure to the service regulator to 60 p.s.i.(414 kPa) gage, a device must be installed between the upstream regulator and service regulator to limit the pressure to the service regulator to 60 p.s.i.(414 kPa) gage or less in case the upstream regulator fails to function properly. This device may be either a regulator, relief valve, or an automatic shutoff that shuts if the pressure on the inlet of the service regulator exceeds 60 p.s.i. (414 kPa) gage, and remains closed until manually reset.
 - (2) A service regulator and a monitoring regulator set to limit, to a safe value, the pressure delivered to the customer. Both regulators must be constructed to withstand the maximum inlet pressure.
 - (3) A service regulator and an automatic shutoff device that closes upon an unsafe rise in pressure downstream from the regulator and remains closed until manually reset.
- (e) If the maximum actual operating pressure does not exceed 125 p.s.i. (862 kPa) gage, a service regulator having the characteristics listed in paragraph (b) of this section and a manufacturer's inlet working pressure rating of 125 p.s.i. (862 kPa) gage or higher, may be used. If the internal relief valve capacity will prevent the downstream pressure from exceeding a safe value, or an overpressure control device is installed, no additional pressure limiting device is required.

§ 192.199 Requirements for Design of Pressure Relief and Limiting Devices

Except for rupture discs, each pressure relief or pressure limiting device must:

- (a) Be constructed of materials such that the operation of the device will not be impaired by corrosion;
- (b) Have valves and valve seats that are designed not to stick in a position that will make the

- device inoperative;
- (c) Be designed and installed so that it can be readily operated to determine if the valve is free, can be tested to determine the pressure at which it will operate, and can be tested for leakage when in the closed position;
 - (d) Have support made of noncombustible material;
 - (e) Have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without undue hazard;
 - (f) Be designed and installed so that the size of the openings, pipe, and fittings located between the system to be protected and the pressure relieving device, and the size of the vent line, are adequate to prevent hammering of the valve and to prevent impairment of relief capacity;
 - (g) Where installed at a district regulator station to protect a pipeline system from overpressuring, be designed and installed to prevent any single incident such as an explosion in a vault or damage by a vehicle from affecting the operation of both the overpressure protective device and the district regulator; and
 - (h) Except for a valve that will isolate the system under protection from its source of pressure, be designed to prevent unauthorized operation of any stop valve that will make the pressure relief valve or pressure limiting device inoperative.
 - (i) Each regulator station must be provided with reasonable protection from physical damage due to vehicles or other causes by being placed in a suitable location or by installation of barricades.

§ 192.201 Required Capacity of Pressure Relieving and Limiting Stations

- (a) Each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline must have enough capacity, and must be set to operate, to insure the following:
 - (1) In a low-pressure distribution system, the pressure may not cause the unsafe operation of any connected and properly adjusted gas utilization equipment.
 - (2) In pipelines other than a low-pressure distribution system:
 - (i) If the maximum allowable operating pressure is 60 p.s.i. (414 kPa) or more, the pressure may not exceed the maximum allowable operating pressure plus 10 percent, or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower;
 - (ii) If the maximum allowable operating pressure is 12 p.s.i. (83 kPa) gage or more, but less than 60 p.s.i. (414 kPa) gage, the pressure may not exceed the maximum allowable operating pressure plus 6 p.s.i. (41kPa) gage; or
 - (iii) If the maximum allowable operating pressure is less than 12 p.s.i. (83 kPa) gage, the pressure may not exceed the maximum allowable operating pressure plus 50 percent.
- (b) When more than one pressure regulating or compressor station feeds into a pipeline, relief valves or other protective devices must be installed at each station to ensure that the complete failure of the largest capacity regulator or compressor, or any single run of lesser capacity regulators or compressors in that station, will not impose pressures on any part

of the pipeline or distribution system in excess of those for which it was designed, or against which it was protected, whichever is lower.

- (c) Relief valves or other pressure limiting devices must be installed at or near each regulator station in a low-pressure distribution system, with a capacity to limit the maximum pressure in the main to a pressure that will not exceed the safe operating pressure for any connected and properly adjusted gas utilization equipment.

§ 192.203 Instrument, Control, and Sampling Pipe and Components

- (a) Applicability. This section applies to the design of instrument, control and sampling pipe and components. It does not apply to permanently closed systems, such as fluid-filled temperature responsive devices.
- (b) Materials and design. All materials employed for pipe and components must be designed to meet the particular conditions of service and the following:
 - (1) Each takeoff connection and attaching boss, fitting, or adapter must be made of suitable material, be able to withstand the maximum service pressure and temperature of the pipe or equipment to which it is attached, and be designed to satisfactorily withstand all stresses without failure by fatigue.
 - (2) Except for takeoff lines that can be isolated from sources of pressure by other valving, a shutoff valve must be installed in each take offline as near as practicable to the point of take-off. Blowdown valves must be installed where necessary.
 - (3) Brass or copper material may not be used for metal temperatures greater than 400°F (204°C).
 - (4) Pipe or components that may contain liquids must be protected by heating or other means from damage due to freezing.
 - (5) Pipe or components in which liquids may accumulate must have drains or drips.
 - (6) Pipe or components subject to clogging from solids or deposits must have suitable connections for cleaning.
 - (7) The arrangement of pipe, components, and supports must provide safety under anticipated operating stresses.
 - (8) Each joint between sections of pipe, and between pipe and valves or fittings, must be made in a manner suitable for the anticipated pressure and temperature condition. Slip type expansion joints may not be used. Expansion must be allowed for by providing flexibility within the system itself.
 - (9) Each control line must be protected from anticipated causes of damage and must be designed and installed to prevent damage to any one control line from making both the regulator and the over-pressure protective device inoperative.

§ 192.204 Risers Installed After January 22, 2019

- (a) Riser designs must be tested to ensure safe performance under anticipated external and internal loads acting on the assembly.
- (b) Factory assembled anodeless risers must be designed and tested in accordance with ASTM F1973-13 (incorporated by reference, see §192.7).
- (c) All risers used to connect regulator stations to plastic mains must be rigid and designed to provide adequate support and resist lateral movement. Anodeless risers used in accordance with this paragraph must have a rigid riser casing.

§ 192.205 Records: Pipeline Components

- (a) For steel transmission pipelines installed after July 1, 2020, an operator must collect or make, and retain for the life of the pipeline, records documenting the manufacturing standard and pressure rating to which each valve was manufactured and tested in accordance with this subpart. Flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi (X42) or greater and with nominal diameters of greater than 2 inches must have records documenting the manufacturing specification in effect at the time of manufacture, including yield strength, ultimate tensile strength, and chemical composition of materials.
- (b) For steel transmission pipelines installed on or before July 1, 2020, if operators have records documenting the manufacturing standard and pressure rating for valves, flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi (X42) or greater and with nominal diameters of greater than 2 inches, operators must retain such records for the life of the pipeline.
- (c) For steel transmission pipeline segments installed on or before July 1, 2020, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of § 192.624 according to the terms of that section.

SUBPART E - WELDING OF STEEL IN PIPELINES

§ 192.221 Scope

- (a) This subpart prescribes minimum requirements for welding steel materials in pipelines.
- (b) This subpart does not apply to welding that occurs during the manufacture of steel pipe or steel pipeline components.

§ 192.225 Welding - Procedures

- (a) Welding must be performed by a qualified welder or welding operator in accordance with welding procedures qualified under section 5 (except for Note 2 in section 5.4.2.2), section 12, Appendix A or Appendix B of API Std 1104 (incorporated by reference, see § 192.7), or Section IX of the ASME Boiler and Pressure Vessel Code (ASME BPVC) (incorporated by reference, see § 192.7) to produce welds meeting the requirements of this subpart. The quality of the test welds used to qualify welding procedures must be determined by destructive testing in accordance with the applicable welding standard(s).
- (b) Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.

§ 192.227 Qualification of Welders and Welding Operators

- (a) Except as provided in paragraph (b) of this section, each welder or welding operator must be qualified in accordance with section 6, section 12, Appendix A or Appendix B of API Std 1104 (incorporated by reference, see § 192.7), or section IX of the ASME Boiler and Pressure Vessel Code (BPVC) (incorporated by reference, see § 192.7). However, a welder or welding operator qualified under an earlier edition than listed in § 192.7 may weld but may not requalify under that earlier edition.
- (b) A welder may qualify to perform welding on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS by performing an acceptable test weld, for the process to be used, under the test set forth in Section I of Appendix C of this

part. Each welder who is to make a welded service line connection to a main must first perform an acceptable test weld under section II of Appendix C of this part as a requirement of the qualifying test.

- (c) For steel transmission pipe installed after July 1, 2021, records demonstrating each individual welder qualification at the time of construction in accordance with this section must be retained for a minimum of 5 years following construction.

§ 192.229 Limitations on Welders and Welding Operators

- (a) No welder or welding operator whose qualification is based on nondestructive testing may weld compressor station pipe and components.
- (b) A welder or welding operator may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder or welding operator was engaged in welding with that process. Alternatively, welders or welding operators may demonstrate they have engaged in a specific welding process if they have performed a weld with that process if they have performed a weld with that process that was tested and found acceptable under section 6, 9, 12, or Appendix A of API Std 1104 (incorporated by reference, see §192.7) within the preceding 7½ months.
- (c) A welder or welding operator qualified under § 192.227(a):
 - (1) May not weld on pipe to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS unless within the preceding 6 calendar months the welder or welding operator has had one weld tested and found acceptable under either section 6, section 9, section 12 or Appendix A of API Std 1104 (incorporated by reference, see § 192.7). Alternatively, welders or welding operators may maintain an ongoing qualification status by performing welds tested and found acceptable under the above acceptance criteria at least twice each calendar year, but at intervals not exceeding 7 ½ months. A welder or welding operator qualified under an earlier edition of a standard listed in § 192.7 of this part may weld but may not re-qualify under that earlier edition; and
 - (2) May not weld on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS unless the welder or welding operator is tested in accordance with paragraph (c)(1) of this section or requalifies under paragraph (d)(1) or (d)(2) of this section.
- (d) A welder or welding operator qualified under § 192.227(b) may not weld unless:
 - (1) Within the preceding 15 calendar months, but at least once each calendar year, the welder or welding operator has re-qualified under § 192.227(b); or
 - (2) Within the preceding 7 1/2 calendar months, but at least twice each calendar year, the welder or welding operator has had -
 - i. A production weld cut out, tested, and found acceptable in accordance with the qualifying test; or
 - ii. For a welder who works only on service lines 2 inches (51 millimeters) or smaller in diameter, the welder has had two sample welds tested and found acceptable in accordance with the test in section III of Appendix C of this part.

§ 192.231 Protection from Weather

The welding operation must be protected from weather conditions that would impair the quality of the completed weld.

§ 192.233 Miter Joints

- (a) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent or more of SMYS may not deflect the pipe more than 3°.
- (b) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of less than 30 percent, but more than 10 percent, of SMYS may not deflect the pipe more than 12 1/2° and must be a distance equal to one pipe diameter or more away from any other miter joint, as measured from the crotch of each joint.
- (c) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 10 percent or less of SMYS may not deflect the pipe more than 90°.

§ 192.235 Preparation for Welding

Before beginning any welding, the welding surfaces must be clean and free of any material that may be detrimental to the weld, and the pipe or component must be aligned to provide the most favorable condition for depositing the root bead. This alignment must be preserved while the root bead is being deposited.

§ 192.241 Inspection and Test of Welds

- (a) Visual inspection of welding must be conducted by an individual qualified by appropriate training and experience to ensure that:
 - (1) The welding is performed in accordance with the welding procedure, and
 - (2) The weld is acceptable under paragraph (c) of this section.
- (b) The welds on a pipeline to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS must be nondestructively tested in accordance with § 192.243, except that welds that are visually inspected and approved by a qualified welding inspector need not be nondestructively tested if:
 - (1) The pipe has a nominal diameter of less than 6 inches (152 millimeters); or
 - (2) The pipeline is to be operated at a pressure that produces a hoop stress of less than 40 percent of SMYS and the welds are so limited in number that nondestructive testing is impractical.
- (c) The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in Section 9 or Appendix A of API Std 1104 (incorporated by reference, see § 192.7). Appendix A of API Std 1104 may not be used to accept cracks.
- (d) Each operator must designate in writing a welding inspector to perform visual inspections of welds under this paragraph.

§ 192.243 Nondestructive Testing

- (a) Nondestructive testing of welds must be performed by any process, other than trepanning, that will clearly indicate defects that may affect the integrity of the weld.
- (b) Nondestructive testing of welds must be performed:
 - (1) In accordance with written procedures; and

- (2) By persons who have been trained and qualified in accordance with the requirements of API Standard 1104. These persons must also be qualified on the equipment employed in the nondestructive testing.
- (c) Procedures must be established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld under § 192.241(c).
- (d) When nondestructive testing is required under § 192.241(b), the following percentages of each day's field butt welds, selected at random by the operator, must be nondestructively tested over their entire circumference:
 - (1) In Class 1 locations, at least 10 percent.
 - (2) In Class 2 locations, at least 15 percent.
 - (3) In Class 3 and 4 locations at crossings of major or navigable rivers and within railroad or public highway rights-of-way, including tunnels, bridges, and overhead road crossings, 100 percent unless impracticable, in which case at least 90 percent. Nondestructive testing must be impracticable for each girth weld not tested.
 - (4) At pipeline tie-ins, including tie-ins of replacement sections, 100 percent.
- (e) Except for a welder or welding operator whose work is isolated from the principal welding activity, a sample of each welder's or welding operator's work for each day must be nondestructively tested, when nondestructive testing is required under § 192.241(b).
- (f) When nondestructive testing is required under § 192.241(b) each operator must retain, for the life of the pipeline, a record showing by milepost, engineering station, or by geographic feature, the number of girth welds made, the number nondestructively tested, the number rejected, and the disposition of the rejects.

§ 192.245 Repair or Removal of Defects

- (a) Each weld that is unacceptable under § 192.241(c) must be removed or repaired. A weld must be removed if it has a crack that is more than 8 percent of the weld length.
- (b) Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability.
- (c) Repair of a crack, or of any defect in a previously repaired area must be in accordance with the written weld repair procedures that have been qualified under § 192.225. Repair procedures must provide that the minimum mechanical properties specified for the welding procedures used to make the original weld are met upon completion of the final weld repair.

SUBPART F - JOINING OF MATERIALS OTHER THAN BY WELDING

§ 192.271 Scope

- (a) This subpart prescribes minimum requirements for joining materials in pipelines, other than by welding.
- (b) This subpart does not apply to joining during the manufacture of pipe or pipeline components.
- (c) Where pipe is to be joined or connections made by threaded couplings all threads will meet the standards of API Standard 5B. All joints will be made up power-tight using a suitable thread sealant.

§ 192.273 General

- (a) The pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading.
- (b) Each joint must be made in accordance with written procedures that have been proven by test or experience to produce strong gas-tight joints.
- (c) Each joint must be inspected to insure compliance with this subpart.

§ 192.275 Cast Iron Pipe

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

§ 192.277 Ductile Iron Pipe

- (a) Ductile iron pipe may not be joined by threaded joints.
- (b) Ductile iron pipe may not be joined by brazing.

§ 192.279 Copper Pipe

Copper pipe may not be threaded, except that copper pipe that is used for joining screw fittings or valves which may be threaded if the wall thickness is equivalent to the comparable size of Schedule 40 or heavier wall pipe listed in ASME B36.10M (incorporated by reference, see § 192.7).

§ 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 D2564-12, for PVC (incorporated by reference, see § 192.7).
 - (3) The joint may not be heated or cooled to accelerate the setting of the cement.
 - (4) Plastic pipe manufactured from different materials shall not be joined by solvent cement joints.
- (c) *Heat-fusion joints.* Each heat-fusion joint on a PE pipe or component, except for electrofusion joints, must comply with ASTM F2620-12 (incorporated by reference in §192.7), or an alternative written procedure that has been demonstrated to provide an equivalent or superior level of safety and has been proven by tests or experience to produce strong gastight joints, and the following:
- (1) A butt heat-fusion joint must be joined by a device that holds the heater element square to the ends of the pipe or component, compresses the heated ends together, and holds the pipe in proper alignment in accordance with the appropriate procedure qualified under § 192.283.
 - (2) A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the pipe or component, uniformly and simultaneously, to establish the same temperature. The device used must be the same device specified in the operator's joining procedure for socket fusion.
 - (3) An electrofusion joint must be made using the equipment and techniques prescribed by the fitting manufacturer, or using equipment and techniques shown, by testing joints to the requirements of § 192.283(a)(1)(iii), to be equivalent to or better than the requirements of the fitting manufacturer.
 - (4) Heat may not be applied with a torch or other open flame.
- (d) *Adhesive joints.* Each adhesive joint on thermosetting plastic pipe must comply with the following:
- (1) The plastic fittings and adhesives must conform to the specifications listed in ASTM D2517 (incorporated by reference, see §192.7).
 - (2) The materials and adhesive must be compatible with each other.
- (e) *Mechanical joints.* Each compression type mechanical joint on plastic pipe must comply with the following:
- (1) Mechanical joints must be gas-tight and installed with materials that will prevent tensile pullouts.
 - (2) The gasket material in the coupling must be compatible with the plastic.
 - (3) All mechanical fittings must meet a listed specification based upon the applicable material.
 - (4) All mechanical joints or fittings installed after January 22, 2019, must be Category 1 as defined by a listed specification for the applicable material, providing a seal plus resistance to a force on the pipe joint equal to or greater than that which will cause no less than 25% elongation of pipe, or the pipe fails outside the joint area if tested in accordance with the applicable standard. Split tubular stiffeners shall not be used.

§ 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 that are made according to the procedure to the following tests, as applicable:
 - (1) The test requirements of -
 - (i) In the case of thermoplastic pipe, based on the pipe material, the Sustained Pressure Test or the Minimum Hydrostatic Burst Test per the listed specification requirements. Additionally, for electrofusion joints, based on the pipe material, the Tensile Strength Test or the Joint Integrity Test per the listed specification.
 - (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 D2517-00 (incorporated by reference, see § 192.7).
 - (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 F1055-98(2006) (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, perform tensile testing in accordance with a listed specification. If the test specimen elongates no less than 25% or failure initiates outside the joint area, the procedure qualifies for use.
- (b) *Mechanical Joints.* Before any written procedure established under § 192.273(b) is used for making mechanical plastic pipe joints, the procedure must be qualified in accordance with a listed specification based upon the pipe material.
- (c) A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints.
- (d) Pipe or fittings manufactured before July 1, 1980 may be used in accordance with procedures that the manufacturer certifies will produce a joint as strong as the pipe.

§192.285 Plastic Pipe: Qualifying Persons To Make Joints.

- (a) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by:
 - (1) Appropriate training or experience in the use of the procedure; and
 - (2) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (b) of this section.
- (b) The specimen joint must be:
 - (1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the

- procedure; and
- (2) In the case of a heat fusion, solvent cement, or adhesive joint;
 - (i) Tested under any one of the test methods listed under §192.283(a), and for PE heat fusion joints (except for electrofusion joints) visually inspected in accordance with ASTM F2620 (incorporated by reference, see § 192.7), or a written procedure that has been demonstrated to provide an equivalent or superior level of safety applicable to the type of joint and material being tested;
 - (ii) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or
 - (iii) Cut into at least three longitudinal straps, each of which is:
 - (A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and
 - (B) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.
 - (c) A person must be re-qualified under an applicable procedure once each calendar year at intervals not exceeding 15 months, or after any production joint is found unacceptable by testing under §192.513.
 - (d) Each operator shall establish a method to determine that each person making joints in plastic pipelines in the operator's system is qualified in accordance with this section.
 - (e) For transmission pipe installed after July 1, 2021, records demonstrating each person's plastic pipe joining qualifications at the time of construction in accordance with this section must be retained for a minimum of 5 years following construction.

§ 192.287 Plastic Pipe: Inspection of Joints

No person may carry out the inspection of joints in plastic pipes required by §§ 192.273(c) and 192.285(b) unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.

SUBPART G - GENERAL CONSTRUCTION REQUIREMENTS FOR TRANSMISSION LINES AND MAINS

§ 192.301 Scope

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

§ 192.303 Compliance with Specifications or Standards

- (a) Each transmission line or main must be constructed in accordance with comprehensive written specifications or standards that are consistent with this Code. Applications or petitions for Certificates of Convenience and Necessity for new construction filed with the Arkansas Public Service Commission shall stipulate that design, construction, testing, operation and maintenance of facility will comply with the requirements of the Arkansas Gas Pipeline Code.
- (b) Each operator of a mobile home park, Federal housing development, or multi-building complex having a master meter, who constructs a distribution system must submit construction plans to the local gas operator for approval before construction is started. The plan shall show the following: location, type, size and specification of pipe; number of services; operating pressure; plans for corrosion control of the pipe, i.e., coating of pipe and cathodic protection. This review will assure all material and construction procedures meet the requirements of this Code. Each owner or operator must certify in writing to the operator supplying gas that the system shall be constructed, tested and inspected in accordance with this Code. This certification must be made to the gas operator before service is connected to the system and will be kept on file by each party for the life of the system.

§ 192.305 Inspection: General

Each transmission line or main must be inspected to ensure that it is constructed in accordance with this subpart. An operator must not use operator personnel to perform a required inspection if the operator personnel performed the construction task requiring inspection. Nothing in this section prohibits the operator from inspecting construction tasks with operator personnel who are involved in other construction tasks.

§ 192.307 Inspection of Materials

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

§ 192.309 Repair of Steel Pipe

- (a) Each imperfection or damage that impairs the serviceability of a length of steel pipe must be repaired or removed. If a repair is made by grinding, the remaining wall thickness must at least be equal to either:
 - (1) The minimum thickness required by the tolerances in the specification to which the pipe was manufactured; or
 - (2) The nominal wall thickness required for the design pressure of the pipeline.
- (b) Each of the following dents must be removed from steel pipe to be operated at a pressure that produces a hoop stress of 20 percent, or more, of SMYS, unless the dent is

repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe:

- (1) A dent that contains a stress concentrator such as a scratch, gouge, groove, or arc burn.
- (2) A dent that affects the longitudinal weld or a circumferential weld.
- (3) In pipe to be operated at a pressure that produces a hoop stress of 40 percent or more of SMYS, a dent that has a depth of:
 - (i) More than 1/4 inch (6.4 millimeters) in pipe 12 3/4 inches (324 millimeters) or less in outer diameter; or
 - (ii) More than 2 percent of the nominal pipe diameter in pipe over 12 3/4 inches (324 millimeters) in outer diameter.

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

- (c) Each arc burn on steel pipe to be operated at a pressure that produces a hoop stress of 40 percent, or more, of SMYS must be repaired or removed. If a repair is made by grinding, the arc burn must be completely removed and the remaining wall thickness must be at least equal to either:
 - (1) The minimum wall thickness required by the tolerances in the specification to which the pipe was manufactured; or
 - (2) The nominal wall thickness required for the design pressure of the pipeline.
- (d) A gouge, groove, arc burn, or dent may not be repaired by insert patching or by pounding out.
- (e) Each gouge, groove, arc burn, or dent that is removed from a length of pipe must be removed by cutting out the damaged portion as a cylinder.

§ 192.311 Repair of Plastic Pipe

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

§ 192.313 Bends and Elbows

- (a) Each field bend in steel pipe, other than a wrinkle bend made in accordance with § 192.315, must comply with the following:
 - (1) A bend must not impair the serviceability of the pipe.
 - (2) Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage.
 - (3) On pipe containing the longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend unless:
 - (i) The bend is made with an internal bending mandrel; or
 - (ii) The pipe is 12 inches (305 millimeters) or less in outside diameter or has a diameter to wall thickness ratio less than 70.
- (b) Each circumferential weld of steel pipe which is located where the stress during bending

causes a permanent deformation in the pipe must be non-destructively tested either before or after the bending process.

- (c) Wrought-steel welding elbows and transverse segments of these elbows may not be used for changes in direction on steel pipe that is 2 inches (51 millimeters) or more in diameter unless the arc length, as measured along the crotch, is at least 1 inch (25 millimeters).
- (d) An operator may not install plastic pipe with a bend radius that is less than the minimum bend radius specified by the manufacturer for the diameter of the pipe being installed.

§ 192.315 Wrinkle Bends in Steel Pipe

- (a) A wrinkle bend may not be made on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent, or more, of SMYS.
- (b) Each wrinkle bend on steel pipe must comply with the following:
 - (1) The bend must not have any sharp kinks.
 - (2) When measured along the crotch of the bend, the wrinkles must be a distance of at least one pipe diameter.
 - (3) On pipe 16 inches (406 millimeters) or larger in diameter, the bend may not have a deflection of more than 1 1/2° for each wrinkle.
 - (4) On pipe containing a longitudinal weld the longitudinal seam must be as near as practicable to the neutral axis of the bend.

§ 192.317 Protection from Hazards

- (a) The operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads.
- (b) Each aboveground transmission line or main must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.
- (c) Pipelines, including pipe risers in inland navigable waters must be protected from accidental damage by vessels.

§ 192.319 Installation of Pipe in a Ditch

- (a) When installed in a ditch, each transmission line that is to be operated at a pressure producing hoop stress of 20 percent or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage.
- (b) Each ditch for a transmission line or main must be backfilled in a manner that:
 - (1) Provides firm support under the pipe; and
 - (2) Prevents damage to the pipe and pipe coating from equipment or from the backfill material.
- (c) Promptly after a ditch for an onshore steel transmission line is backfilled (if the construction project involves 1,000 feet or more of continuous backfill length along the pipeline), but not later than 6 months after placing the pipeline in service, the operator must perform an assessment to assess any coating damage and ensure integrity of the coating using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology that provides comparable information about the integrity of the coating.

Coating surveys must be conducted, except in locations where effective coating surveys are precluded by geographical, technical, or safety reasons.

- (d) An operator must notify PHMSA in accordance with § 192.18 at least 90 days in advance of using other technology to assess integrity of the coating under paragraph (c) of this section.
- (e) An operator of an onshore steel transmission pipeline must develop a remedial action plan and apply for any necessary permits within 6 months of completing the assessment that identified the deficiency. An operator must repair any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dB μ V for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within 6 months of the assessment, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after the receipt of permits.
- (f) An operator of an onshore steel transmission pipeline must make and retain for the life of the pipeline records documenting the coating assessment findings and remedial actions performed under paragraphs (c) – (e) of this section.

§ 192.321 Installation of Plastic Pipe

- (a) Plastic pipe must be installed below ground level except as provided by paragraphs (g) and (h) and (i) of this section.
- (b) Plastic pipe that is installed in a vault or any other below grade enclosure must be completely encased in gas-tight metal pipe and fittings that are adequately protected from corrosion.
- (c) Plastic pipe must be installed so as to minimize shear or tensile stresses.
- (d) Plastic pipe must have a minimum wall thickness in accordance with § 192.121.
- (e) Plastic pipe that is not encased must have an electrically conducting wire or other means of locating the pipe while it is underground. Tracer wire may not be wrapped around the pipe and contact with the pipe must be minimized but is not prohibited. Tracer wire or other metallic elements installed for pipe locating purposes must be resistant to corrosion damage, either by use of coated copper wire or by other means.
- (f) Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. Plastic pipe that is being encased must be protected from damage at all entrance and all exit points of the casing. The leading end of the plastic must be closed before insertion.
- (g) With written permission from the state Pipeline Safety Office, uncased plastic pipe may be temporarily installed above ground level under the following conditions:
 - (1) The operator must be able to demonstrate that the cumulative aboveground exposure of the pipe does not exceed the manufacturer's recommended maximum period of exposure or 2 years, whichever is less.
 - (2) The pipe either is located where damage by external forces is unlikely or is otherwise protected against such damage.
 - (3) The pipe adequately resists exposure to ultraviolet light and high and low temperatures.
- (h) Plastic pipe may be installed on bridges provided that it is:
 - (1) Installed with protection from mechanical damage, such as installation in a metallic

- casing;
 - (2) Protected from ultraviolet radiation; and
 - (3) Not allowed to exceed the pipe temperature limits specified in § 192.121.
- (i) Plastic mains may terminate above ground level provided they comply with the following:
- (1) The above-ground level part of the plastic main is protected against deterioration and external damage.
 - (2) The plastic main is not used to support external loads.
 - (3) Installations of risers at regulator stations must meet the design requirements of §192.204.

§ 192.323 Casing

Each casing used on a transmission line or main under a railroad or highway must comply with the following:

- (a) The casing must be designed to withstand the superimposed loads.
- (b) If there is a possibility of water entering the casing, the ends must be sealed.
- (c) If the ends of an unvented casing are sealed and the sealing is strong enough to retain the maximum allowable operating pressure of the pipe, the casing must be designed to hold this pressure at a stress level of not more than 72 percent of SMYS.
- (d) If vents are installed on a casing, the vents must be protected from the weather to prevent water from entering the casing.

§ 192.325 Underground Clearance

- (a) Each transmission line must be installed with at least 12 inches (305 millimeters) of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, the transmission line must be protected from damage that might result from the proximity of the other structure.
- (b) Each main must be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures.
- (c) In addition to meeting the requirements of paragraph (a) or (b) of this section, each plastic transmission line or main must be installed with sufficient clearance, or must be insulated, from any source of heat so as to prevent the heat from impairing the serviceability of the pipe.
- (d) Each pipe-type or bottle-type holder must be installed with a minimum clearance from any other holder as prescribed in § 192.175(b).

§ 192.327 Cover

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

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

- (b) Except as provided in paragraphs (c) and (d) of this section, each buried main must be installed with at least 24 inches (610 millimeters) of cover.
- (c) Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.
- (d) A main may be installed with less than 24 inches (610 millimeters) of cover if the law of the State or municipality:
 - (1) Establishes a minimum cover of less than 24 inches (610 millimeters);
 - (2) Requires that mains be installed in a common trench with other utility lines; and
 - (3) Provides adequately for prevention of damage to the pipe by external forces.
- (e) Except as provided in paragraph (c) of this section, all pipe installed in a navigable river, stream, or harbor must be installed with a minimum cover of 48 inches (1,219 millimeters) in soil or 24 inches (610 millimeters) in consolidated rock between the top of the pipe and the underwater natural bottom (as determined by recognized and generally accepted practices).

§ 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

	<p>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.</p>
	<p>(2) The quality assurance plan for applying and testing field applied coating to girth welds must be:</p>
	<p>(i) Equivalent to that required under § 192.112(f)(3) for pipe; and</p>
	<p>(ii) Performed by an individual with the knowledge, skills, and ability to assure effective coating application.</p>
<p>(b) Girth welds</p>	<p>(1) All girth welds on a new pipeline segment must be non-destructively examined in accordance with § 192.243(b) and (c).</p>
<p>(c) Depth of cover</p>	<p>(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.</p>
	<p>(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.</p>
<p>(d) Initial strength testing</p>	<p>(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.</p>

(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.
---------------------------	--

§192.329 Installation Of Plastic Pipelines By Trenchless Excavation.

Plastic pipelines installed by trenchless excavation must comply with the following:

- (a) Each operator must take practicable steps to provide sufficient clearance for installation and maintenance activities from other underground utilities and/or structures at the time of installation.
- (b) For each pipeline section, plastic pipe and components that are pulled through the ground must use a weak link, as defined by §192.3, to ensure the pipeline will not be damaged by any excessive forces during the pulling process.

SUBPART H - CUSTOMER METERS, SERVICE REGULATORS, AND SERVICE LINES

§ 192.351 Scope

This subpart prescribes minimum requirements for installing customer meters, service regulators, service lines, service line valves, and service line connections to mains.

§ 192.353 Customer Meters and Regulators: Location

- (a) Each meter and service regulator, whether inside or outside a building, must be installed in a readily accessible location and be protected from corrosion and other damage, including, if installed outside a building, vehicular damage that may be anticipated.
- (b) Each service regulator installed within a building must be located as near as practical to the point of service line entrance.
- (c) Each meter installed within a building must be located in a ventilated place and not less than 3 feet (914 millimeters) from any source of ignition or any source of heat which might damage the meter.
- (d) Where feasible, meters and regulators previously installed inside of buildings will be relocated to outside of building when the regulator or meter is removed for any reason.

§ 192.355 Customer Meters and Regulators: Protection from Damage

- (a) *Protection from vacuum or back pressure.* If the customer's equipment might create either a vacuum or a back pressure, a device must be installed to protect the system.
- (b) *Service regulator vents and relief vents.* Service regulator vents and relief vents must terminate outdoors, and the outdoor terminal must—
 - (1) Be rain and insect resistant;
 - (2) Be located at a place where gas from the vent can escape freely into the

atmosphere and away from any opening into the building; and

- (3) Be protected from damage caused by submergence in areas where flooding may occur.
- (c) *Pits and vaults.* Each pit or vault that houses a customer meter or regulator at a place where vehicular traffic is anticipated, must be able to support that traffic.

§ 192.357 Customer Meters and Regulators: Installation

- (a) Each meter and each regulator must be installed so as to minimize anticipated stresses upon the connecting piping and the meter.
- (b) When close all-thread nipples are used, the wall thickness remaining after the threads are cut must meet the minimum wall thickness requirements of this part.
- (c) Connections made of lead or other easily damaged material may not be used in the installation of meters or regulators.
- (d) Each regulator that might release gas in its operation must be vented to the outside atmosphere.

§ 192.359 Customer Meter Installations: Operating Pressure

- (a) A meter may not be used at a pressure that is more than 67 percent of the manufacturer's shell test pressure.
- (b) Each newly installed meter manufactured after November 12, 1970, must have been tested to a minimum of 10 p.s.i. (69 kPa) gage.
- (c) A rebuilt or repaired tinned steel case meter may not be used at a pressure that is more than 50 percent of the pressure used to test the meter after rebuilding or repairing.

§ 192.361 Service Lines: Installation

- (a) *Depth.* Each buried service line must be installed with at least 12 inches (305 millimeters) of cover in private property and at least 18 inches (457 millimeters) of cover in streets and roads. However, where an underground structure prevents installation at those depths, the service line must be able to withstand any anticipated external load.
- (b) *Support and backfill.* Each service line must be properly supported on undisturbed or well-compacted soil, and material used for backfill must be free of materials that could damage the pipe or its coating.
- (c) *Grading for drainage.* Where condensate in the gas might cause interruption in the gas supply to the customer, the service line must be graded so as to drain into the main or into drips at the low points in the service line.
- (d) *Protection against piping strain and external loading.* Each service line must be installed so as to minimize anticipated piping strain and external loading.
- (e) *Installation of service lines into buildings.* Each underground service line installed below grade through the outer foundation wall of a building must:
 - (1) In the case of a metal service line, be protected against corrosion;
 - (2) In the case of plastic service line, be protected from shearing action and backfill settlement; and
 - (3) Be sealed at the foundation wall to prevent leakage into the building.

- (f) *Installation of service lines under buildings.* Where an underground service line is installed under a building;
 - (1) It must be encased in a gas tight conduit;
 - (2) The conduit and the service line must, if the service line supplies the building it underlies, extend into a normally usable and accessible part of the building; and
 - (3) The space between the conduit and the service line must be sealed to prevent gas leakage into the building and, if the conduit is sealed at both ends, a vent line from the annular space must extend to a point where gas would not be a hazard, and extend above grade, terminating in a rain and insect resistant fitting.
- (g) *Locating underground service lines.* Each underground nonmetallic service line that is not encased must have a means of locating the pipe that complies with § 192.321(e).
- (h) *Service lines installed by other than gas company personnel.* These person(s) shall certify to the gas company that the line(s) were installed in accordance with this code.

§ 192.363 Service Lines: Valve Requirements

- (a) Each service line must have a service-line valve that meets the applicable requirements of Subparts B and D of this part. A valve incorporated in a meter bar, that allows the meter to be bypassed, may not be used as a service-line valve.
- (b) A soft seat service line valve may not be used if its ability to control the flow of gas could be adversely affected by exposure to anticipated heat.
- (c) Each service-line valve on a high-pressure service line, installed above ground or in an area where the blowing of gas would be hazardous, must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools.

§ 192.365 Service Lines: Location of Valves

- (a) *Relation to regulator or meter.* Each service-line valve must be installed upstream of the regulator or, if there is no regulator, upstream of the meter.
- (b) *Outside valves.* Each service line must have a shut-off valve in a readily accessible location that, if feasible, is outside of the building.
- (c) *Underground valves.* Each underground service-line valve must be located in a covered durable curb box or standpipe that allows ready operation of the valve and is supported independently of the service lines.

§ 192.367 Service Lines: General Requirements for Connections to Main Piping

- (a) *Location.* Each service line connection to a main must be located at the top of the main or, if that is not practical, at the side of the main, unless a suitable protective device is installed to minimize the possibility of dust and moisture being carried from the main into the service line.
- (b) *Compression-type connection to mains.* Each compression-type service line to main connection must:
 - (1) Be designed and installed to effectively sustain the longitudinal pull-out or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading;
 - (2) If gaskets are used in connecting the service line to the main connection fitting, have gaskets that are compatible with the kind of gas in the system:and

- (3) If used on pipelines comprised of plastic, be a Category 1 connection as defined by a listed specification for the applicable material, providing a seal plus resistance to a force on the pipe joint equal to or greater than that which will cause no less than 25% elongation of pipe, or the pipe fails outside the joint area if tested in accordance with the applicable standard.

§ 192.369 Service Lines: Connection to Cast Iron or Ductile Iron Mains

- (a) Each service line connected to a cast iron or ductile iron main must be connected by a mechanical clamp, by drilling and tapping the main, or by another method meeting the requirements of § 192.273.
- (b) If a threaded tap is being inserted, the requirements of §§ 192.151(b) and (c) must also be met.

§ 192.371 Service Lines: Steel

Each steel service line to be operated at less than 100 p.s.i. (689 kPa) gage must be constructed of pipe designed for a minimum of 100 p.s.i. (689 kPa) gage.

§ 192.373 Service Lines: Cast Iron and Ductile Iron

- (a) Cast or ductile iron pipe less than 6 inches (152 millimeters) in diameter may not be installed for service lines.
- (b) If cast iron pipe or ductile iron pipe is installed for use as a service line, the part of the service line which extends through the building wall must be of steel pipe.
- (c) A cast iron or ductile iron service line may not be installed in unstable soil or under a building.

§ 192.375 Service Lines: Plastic

- (a) Each plastic service line outside a building must be installed below ground level, except that it may terminate above the ground and outside the building, if:
 - (1) The above ground part of the plastic service line is protected against deterioration and external damage; and
 - (2) It may terminate above ground level and outside the building, if -
 - (i) The above ground level part of the plastic service line is protected against deterioration and external damage;
 - (ii) The plastic service line is not used to support external loads; and
 - (iii) The riser portion of the service line meets the design requirements of §192.204.

Each plastic service line inside a building must be protected from external damage.

§ 192.376 Installation Of Plastic Service Lines By Trenchless Excavation

Plastic service lines installed by trenchless excavation must comply with the following:

- (a) Each operator shall take practicable steps to provide sufficient clearance for installation and maintenance activities from other underground utilities and structures at the time of installation.
- (b) For each pipeline section, plastic pipe and components that are pulled through the ground must use a weak link, as defined by §192.3, to ensure the pipeline will not be damaged

by any excessive forces during the pulling process.

§ 192.377 Service Lines: Copper

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

§ 192.379 New Service Lines Not in Use

Each service line that is not placed in service upon completion of installation must comply with one of the following until the customer is supplied with gas:

- (a) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.
- (b) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.
- (c) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

§ 192.381 Service Lines: Excess Flow Valve Performance Standards

- (a) Excess flow valves (EFVs) to be used on service lines that operate continuously throughout the year at a pressure not less than 10 p.s.i. (69 kPa) gage must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer's specification, to ensure that each valve will:
 - (1) Function properly up to the maximum operating pressure at which the valve is rated;
 - (2) Function properly at all temperatures reasonably expected in the operating environment of the service line;
 - (3) At 10 p.s.i. (69 kPa) gage:
 - (i) Close at, or not more than 50 percent above, the rated closure flow rate specified by the manufacturer; and
 - (ii) Upon closure, reduce gas flow -
 - (A) For an excess flow valve designed to allow pressure to equalize across the valve, to no more than 5 percent of the manufacturer's specified closure flow rate, up to a maximum of 20 cubic feet per hour (0.57 cubic meters per hour); or
 - (B) For an excess flow valve designed to prevent equalization of pressure across the valve, to no more than 0.4 cubic feet per hour (.01 cubic meters per hour); and
 - (4) Not to close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate.
- (b) An excess flow valve must meet the applicable requirements of subparts B and D of this part.
- (c) An operator must mark or otherwise identify the presence of an excess flow valve in the service line.
- (d) An operator shall locate an excess flow valve as near as practical to the fitting

connecting the service line to its source of gas supply.

- (e) An operator should not install an excess flow valve on a service line where the operator has prior experience with contaminants in the gas stream, where these contaminants could be expected to cause the excess flow valve to malfunction or where the excess flow valve would interfere with the necessary operation and maintenance activities on the service, such as blowing liquids from the line.

§ 192.383 Excess Flow Valve Installation

- (a) Definitions. As used in this section:

Branched service line means a gas service line that begins at the existing service line or is installed concurrently with the primary service line but serves a separate residence.

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 (SFR).

- (b) *Installation required.* An EFV installation must comply with the performance standards in §192.381. After April 14, 2017, each operator must install an EFV on any new or replace service line serving the following types of services before the line is activated:

- (1) A single service line to one SFR;
- (2) A branched service line to a SFR installed concurrently with the primary SFR service line (i.e., a single EFV may be installed to protect both service lines);
- (3) A branched service line to a SFR installed off a previously installed SFR service line that does not contain an EFV;
- (4) Multifamily residences with known customer loads not exceeding 1,000 SCFH per service, at time of service installation based on installed meter capacity, and
- (5) A single, small commercial customer served by a single service line with a known customer load not exceeding 1,000 SCFH, at the time of meter installation, based on installed meter capacity.

- (c) *Exceptions to excess flow valve installation requirement.* An operator need not install an excess flow valve if one or more of the following conditions are 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 customer;
- (3) An EFV could interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or
- (4) An EFV meeting the performance standards in § 192.381 is not commercially available to the operator.

- (d) *Customer's right to request an EFV.* Existing service line customers who desire an EFV on service lines not exceeding 1,000 SCFH and who do not qualify for one of the exceptions in paragraph (c) of this section may request an EFV to be installed on their service lines. If an eligible service line customer requests an EFV installation, an operator must install the EFV at a mutually agreeable date. The operator's rate-setter determines

how and to whom the costs of the requested EFVs are distributed.

- (e) *Operator notification of customers concerning EFV installation.* Operators must notify customers of their right to request an EFV in the following manner:
- (1) Except as specified in paragraphs (c) and (e)(5) of this section, each operator must provide written or electronic notification to customers of their right to request the installation of an EFV. Electronic notification can include emails, Web site postings, and e-billing notices.
 - (2) The notification must include an explanation for the service line customer of the potential safety benefits that may be derived from installing an EFV. The explanation must include information that an EFV is designed to shut off the flow of natural gas automatically if the service line breaks.
 - (3) The notification must include a description of EFV installation and replacement costs. The notice must alert the customer that the costs for maintaining and replacing an EFV may later be incurred, and what those costs will be to the extent known.
 - (4) The notification must indicate that if a service line customer requests installation of an EFV and the load does not exceed 1,000 SCFH and the conditions of paragraph (c) are not present, the operator must install an EFV at a mutually agreeable date.
 - (5) Operators of master-meter systems and liquefied petroleum gas (LPG) operators with fewer than 100 customers may continuously post a general notification in a prominent location frequented by customers.
- (f) *Operator evidence of customer notification.* An operator must make a copy of the notice or notices currently in use available during PHMSA inspections or State inspections conducted under a pipeline safety program certified or approved by PHMSA under 49 U.S.C. 60105 or 60106.
- (g) *Reporting.* Except for operators of master-meter systems and LPG operators with fewer than 100 customers, each operator must report the EFV measures detailed in the annual report required by § 191.11.

§ 192.385 Manual service line shut-off valve installation.

- (a) *Definitions.* As used in this section:
- Manual service line shut-off valve* means a curb valve or other manually operated valve located near the service line that is safely accessible to operator personnel or other personnel authorized by the operator to manually shut off gas flow to the service line, if needed.
- (b) *Installation requirement.* The operator must install either a manual service line shut-off valve or, if possible, based on sound engineering analysis and availability, an EFV for any new or replaced service line with installed meter capacity exceeding 1,000 SCFH.
- (c) *Accessibility and maintenance.* Manual service line shut-off valves for any new or replaced service line must be installed in such a way as to allow accessibility during emergencies. Manual service shut-off valves installed under this section are subject to regular scheduled maintenance, as documented by the operator and consistent with the valve manufacturer's specification.

SUBPART I - REQUIREMENTS FOR CORROSION CONTROL

§ 192.451 Scope

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

§ 192.452 How does this subpart apply to converted pipelines and regulated onshore gathering lines?

- (a) *Converted pipelines.* Notwithstanding the date the pipeline was installed or any earlier deadlines for compliance, each pipeline which qualifies for use under this part in accordance with § 192.14 must meet the requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, and all other applicable requirements within 1 year after the pipeline is readied for service. However, the requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply if the pipeline substantially meets those requirements before it is readied for service or it is a segment which is replaced, relocated, or substantially altered.
- (b) *Type A and B onshore gathering lines.* For any Type A and Type B regulated onshore gathering line under § 192.9 existing on April 14, 2006, that was not previously subject to this part, and for any onshore gathering line that becomes a regulated onshore gathering line under § 192.9 after April 14, 2006, because of a change in class location or increase in dwelling density:
 - (1) The requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, apply to the gathering line regardless of the date the pipeline was actually installed; and
 - (2) The requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply only if the pipeline substantially meets those requirements.
- (c) *Type C onshore regulated gathering lines.* For any Type C onshore regulated gathering pipeline under § 192.9 existing on May 16, 2022, that was not previously subject to this part, and for any Type C onshore gas gathering pipeline that becomes subject to this subpart after May 16, 2022, because of an increase in MAOP, change in class location, or presence of a building intended for human occupancy or other impacted site:
 - (1) The requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, apply to the gathering line regardless of the date the pipeline was actually installed; and
 - (2) The requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply only if the pipeline substantially meets those requirements.
- (d) *Regulated onshore gathering lines generally.* Any gathering line that is subject to this subpart per § 192.9 at the time of construction must meet the requirements of this subpart applicable to pipelines installed after July 31, 1971.

§ 192.453 General

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

§ 192.455 External Corrosion Control: Buried or Submerged Pipelines Installed After July 31, 1971

- (a) Except as provided in paragraphs (b), (c), (f), and (g) of this section, each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following:
 - (1) It must have an external protective coating meeting the requirements of § 192.461.
 - (2) It must have a cathodic protection system designed to protect the pipeline in its entirety in accordance with this subpart, installed and placed in operation within one year after completion of construction.
- (b) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience in the area of application, including, as a minimum, soil resistivity measurements and tests for corrosion accelerating bacteria, that a corrosive environment does not exist. However, within 6 months after an installation made pursuant to the preceding sentence, the operator shall conduct tests, including pipe-to-soil potential measurements with respect to either a continuous reference electrode or an electrode using close spacing, not to exceed 20 feet (6 meters), and soil resistivity measurements at potential profile peak locations, to adequately evaluate the potential profile along the entire pipeline. If the tests made indicate that a corrosive condition exists, the pipeline must be cathodically protected in accordance with paragraph (a)(2) of this section.
- (c) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience that:
 - (1) For a copper pipeline, a corrosive environment does not exist; or
 - (2) For a temporary pipeline with an operating period of service not to exceed 5 years beyond installation, corrosion during the 5- year period of service of the pipeline will not be detrimental to public safety.
- (d) Notwithstanding the provisions of paragraph (b) or (c) of this section, if a pipeline is externally coated, it must be cathodically protected in accordance with paragraph (a)(2) of this section.
- (e) Aluminum may not be installed in a buried or submerged pipeline if that aluminum is exposed to an environment with a natural pH in excess of 8, unless tests or experience indicates its suitability in the particular environment involved.
- (f) This section does not apply to electrically isolated, metal alloy fittings in plastic pipelines if:
 - (1) For the size fitting to be used, an operator can show by tests, investigation, or experience in the area of application, that adequate corrosion control is provided by the alloy composition; and
 - (2) The fitting is designed to prevent leakage caused by localized corrosion pitting.
- (g) Electrically isolated metal alloy fittings installed after January 22, 2019, that do not meet the requirements of paragraph (f) must be cathodically protected, and must be maintained in accordance with the operator's integrity management plan.

§ 192.457 External Corrosion Control: Buried or Submerged Pipelines Installed Before August 1, 1971

- (a) Except for buried piping at compressor, regulator, and measuring stations, each buried or submerged transmission line installed before August 1, 1971, that has an effective external coating must be cathodically protected along the entire area that is effectively coated, in accordance with this subpart. For the purposes of this subpart, a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The operator shall make tests to determine the cathodic protection current requirements.
- (b) Except for cast iron or ductile iron, each of the following buried or submerged pipelines installed before August 1, 1971, must be cathodically protected in accordance with this subpart in areas in which active corrosion is found:
 - (1) Bare or ineffectively coated transmission lines.
 - (2) Bare or coated pipes at compressor, regulator, and measuring stations.
 - (3) Bare or coated distribution lines.

§ 192.459 External Corrosion Control: Examination of Buried Pipeline when Exposed

Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion, if bare or the coating is deteriorated, must be examined for evidence of external corrosion. If external corrosion requiring remedial action under §§ 192.483 through 192.489 is found, the operator shall investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

§ 192.461 External Corrosion Control: Protective Coating

- (a) Each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must:
 - (1) Be applied on a properly prepared surface;
 - (2) Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture;
 - (3) Be sufficiently ductile to resist cracking;
 - (4) Have sufficient strength to resist damage due to handling (including, but not limited to, transportation, installation, boring, and backfilling) and soil stress; and
 - (5) Have properties compatible with any supplemental cathodic protection.
- (b) Each external protective coating which is an electrically insulating type must also have low moisture absorption and high electrical resistance.
- (c) Each external protective coating must be inspected just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired.
- (d) Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.

- (e) If coated pipe is installed by boring, driving, or other similar methods, precautions must be taken to minimize damage to the coating during installation.
- (f) Promptly after the backfill of an onshore steel transmission pipeline ditch following repair or replacement (if the repair or replacement results in 1,000 feet or more of backfill length along the pipeline), but no later than 6 months after the backfill, the operator must perform an assessment to assess any coating damage and ensure integrity of the coating using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology that provides comparable information about the integrity of the coating. Coating surveys must be conducted, except in locations where effective coating surveys are precluded by geographical, technical, or safety reasons.
- (g) An operator must notify PHMSA in accordance with § 192.18 at least 90 days in advance of using other technology to assess integrity of the coating under paragraph (f) of this section.
- (h) An operator of an onshore steel transmission pipeline must develop a remedial action plan and apply for any necessary permits within 6 months of completing the assessment that identified the deficiency. The operator must repair any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dB μ V for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within 6 months of the assessment, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after the receipt of permits.
- (i) An operator of an onshore steel transmission pipeline must make and retain for the life of the pipeline records documenting the coating assessment findings and remedial actions performed under paragraphs (f) through (h) of this section.

§ 192.463 External Corrosion Control: Cathodic Protection

- (a) Each cathodic protection system required by this subpart must provide a level of cathodic protection that complies with one or more of the applicable criteria contained in Appendix D of this subpart. If none of these criteria is applicable, the cathodic protection system must provide a level of cathodic protection at least equal to that provided by compliance with one or more of these criteria.
- (b) If amphoteric metals are included in a buried or submerged pipeline containing a metal of different anodic potential:
 - (1) The amphoteric metals must be electrically isolated from the remainder of the pipeline and cathodically protected; or
 - (2) The entire buried or submerged pipeline must be cathodically protected at a cathodic potential that meets the requirements of Appendix D of this part for amphoteric metals.
- (c) The amount of cathodic protection must be controlled so as not to damage the protective coating or the pipe.

§ 192.465 External Corrosion Control: Monitoring

- (a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of § 192.463. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of 100 feet (30 meters), or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures,

distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period.

- (b) Cathodic protection rectifiers and impressed current power sources must be periodically inspected as follows:
 - (1) Each cathodic protection rectifier or impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2 ½ months between inspections, to ensure adequate amperage and voltage levels needed to provide cathodic protection are maintained. This may be done either through remote measurement or through an onsite inspection of the rectifier.
 - (2) After January 1, 2022, each remotely inspected rectifier must be physically inspected for continued safe and reliable operation at least once each calendar year, but with intervals not exceeding 15 months.
- (c) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance six times each calendar year, but with intervals not exceeding 2 1/2 months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.
- (d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the 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.

§ 192.467 External Corrosion Control: Electrical Isolation

- (a) Each buried or submerged pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.
- (b) One or more insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.
- (c) Except for unprotected copper inserted in ferrous pipe, each pipeline must be electrically isolated from metallic casings that are a part of the underground system. However, if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing.
- (d) Inspection and electrical tests must be made to assure that electrical isolation is adequate.
- (e) An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.
- (f) Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating

devices.

§ 192.469 External Corrosion Control: Test Stations

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

§ 192.471 External Corrosion Control: Test Leads

- (a) Each test lead wire must be connected to the pipeline so as to remain mechanically secure and electrically conductive.
- (b) Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe.
- (c) Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

§ 192.473 External Corrosion Control: Interference Currents

- (a) Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of such currents.
- (b) Each impressed current type cathodic protection system or galvanic anode system must be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures.
- (c) For onshore gas transmission pipelines, the program required by paragraph (a) of this section must include:
 - (1) Interference surveys for a pipeline system to detect the presence and level of any electrical stray current. Interference surveys must be conducted when potential monitoring indicates a significant increase in stray current, or when new potential stray current sources are introduced, such as through co-located pipelines, structures, or high voltage alternating current (HVAC) power lines, including from additional generation, a voltage up-rating, additional lines, new or enlarged power substations, or new pipelines or other structures;
 - (2) Analysis of the results of the survey to determine the cause of the interference and whether the level could cause significant corrosion, impede safe operation, or adversely affect the environment or public;
 - (3) Development of a remedial action plan to correct any instances where interference current is greater than or equal to 100 amps per meter squared alternating current (AC), or if it impedes the safe operation of a pipeline, or if it may cause a condition that would adversely impact the environment or the public; and
 - (4) Application for any necessary permits within 6 months of completing the interference survey that identified the deficiency. An operator must complete remedial actions promptly, but no later than the earliest of the following: within 15 months after completing the interference survey that identified the deficiency; or as soon as practicable, but not to exceed 6 months, after obtaining any necessary permits.

§ 192.475 Internal Corrosion Control: General

- (a) Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal

corrosion.

- (b) Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. If internal corrosion is found:
 - (1) The adjacent pipe must be investigated to determine the extent of internal corrosion;
 - (2) Replacement must be made to the extent required by the applicable paragraphs of §§ 192.485, 192.487, or 192.489; and
 - (3) Steps must be taken to minimize the internal corrosion.
- (c) Gas containing more than 0.1 grain of hydrogen sulfide per 100 cubic feet (2.32 milligrams/m³) at standard conditions may not be stored in pipe-type or bottle-type holders.

§ 192.476 Internal Corrosion Control: Design and Construction of Transmission Line

- (a) *Design and construction.* Except as provided in paragraph (b) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must have features incorporated into its design and construction to reduce the risk of internal corrosion. At a minimum, unless it is impracticable or unnecessary to do so, each new transmission line or replacement of line pipe, valve, fitting or other line component in a transmission line must:
 - (1) Be configured to reduce the risk that liquids will collect in the line;
 - (2) Have effective liquid removal features whenever the configuration would allow liquids to collect; and
 - (3) Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion.
- (b) *Exceptions to applicability.* The design and construction requirements of paragraph (a) of this section do not apply to the following:
 - (1) Offshore pipeline; and
 - (2) Pipeline installed or line pipe, valve, fitting or other line component replaced before May 23, 2007.
- (c) *Change to existing transmission line.* When an operator changes the configuration of a transmission line, the operator must evaluate the impact of the change on internal corrosion risk to the downstream portion of an existing onshore transmission line and provide for removal of liquids and monitoring of internal corrosion as appropriate.
- (d) *Records.* An operator must maintain records demonstrating compliance with this section. Provided the records show why incorporating design features addressing paragraph (a)(1), (a)(2), or (a)(3) of this section is impracticable or unnecessary, an operator may fulfill this requirement through written procedures supported by as-built drawings or other construction records.

§ 192.477 Internal Corrosion Control: Monitoring

If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with intervals not exceeding 7 1/2 months.

§ 192.478 Internal corrosion control: Onshore transmission monitoring and mitigation.

- (a) Each operator of an onshore gas transmission pipeline with corrosive constituents in the gas being transported must develop and implement a monitoring and mitigation program to mitigate the corrosive effects, as necessary. Potentially corrosive constituents include, but are not limited to: carbon dioxide, hydrogen sulfide, sulfur, microbes, and liquid water, either by itself or in combination. An operator must evaluate the partial pressure of each corrosive constituent, where applicable, by itself or in combination, to evaluate the effect of the corrosive constituents on the internal corrosion of the pipe and implement mitigation measures as necessary.
- (b) The monitoring and mitigation program described in paragraph (a) of this section must include:
 - (1) The use of gas-quality monitoring methods at points where gas with potentially corrosive contaminants enters the pipeline to determine the gas stream constituents.
 - (2) Technology to mitigate the potentially corrosive gas stream constituents. Such technologies may include product sampling, inhibitor injections, in-line cleaning pigging, separators, or other technology that mitigates potentially corrosive effects.
 - (3) An evaluation at least once each calendar year, at intervals not to exceed 15 months, to ensure that potentially corrosive gas stream constituents are effectively monitored and mitigated.
- (c) An operator must review its monitoring and mitigation program at least once each calendar year, at intervals not to exceed 15 months, and based on the results of its monitoring and mitigation program, implement adjustments, as necessary.

§ 192.479 Atmospheric Corrosion Control: General

- (a) Each operator must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under paragraph (c) of this section.
- (b) Coating material must be suitable for the prevention of atmospheric corrosion.
- (c) Except portions of pipelines in offshore splash zones or soil-to-air interfaces, the operator need not protect from atmospheric corrosion any pipeline for which the operator demonstrates by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will--
 - (1) Only be a light surface oxide; or
 - (2) Not affect the safe operation of the pipeline before the next scheduled inspection.

§ 192.481 Atmospheric Corrosion Control: Monitoring

- (a) Each operator must inspect and evaluate each pipeline or portion of the pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

Pipeline type:	Then the frequency of inspection is:
(1) Onshore other than a Service Line	At least once every 3 calendar years, but with intervals not exceeding 39 months.
(2) Onshore Service Line	At least once every 5 calendar years, but with intervals not exceeding 63 months, except as provided in paragraph (d) of this section.
(3) Offshore	At least once each calendar year, but with intervals not exceeding 15 months.

- (b) During inspections the operator must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.
- (c) If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by § 192.479.
- (d) If atmospheric corrosion is found on a service line during the most recent inspection, then the next inspection of that pipeline or portion of pipeline must be within 3 calendar years, but with intervals not exceeding 39 months.

§ 192.483 Remedial Measures: General

- (a) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of § 192.461.
- (b) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected in accordance with this subpart.
- (c) Except for cast iron or ductile iron pipe, each segment of buried or submerged pipe that is required to be repaired because of external corrosion must be cathodically protected in accordance with this subpart.

§ 192.485 Remedial Measures: Transmission Lines

- (a) *General corrosion.* Each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for the MAOP of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.
- (b) *Localized corrosion pitting.* Each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.
- (c) *Calculating remaining strength.* Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness must be determined and documented in accordance with § 192.712.

§ 192.487 Remedial Measures: Distribution Lines Other Than Cast Iron or Ductile Iron Lines

- (a) *General corrosion.* Except for cast iron or ductile iron pipe, each segment of generally corroded distribution line pipe with a remaining wall thickness less than that required for the MAOP of the pipeline, or a remaining wall thickness less than 30 percent of the nominal wall thickness, must be replaced. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.
- (b) *Localized corrosion pitting.* Except for cast iron or ductile iron pipe, each segment of distribution line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired.

§ 192.489 Remedial Measures: Cast Iron and Ductile Iron Pipelines

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

§ 192.490 Direct Assessment

Each operator that uses direct assessment as defined in § 192.903 on an onshore transmission line made primarily of steel or iron to evaluate the effects of a threat in the first column must carry out the direct assessment according to the standard listed in the second column. These standards do not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process.

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

§ 192.491 Corrosion Control Records

- (a) Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system. Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.
- (b) Each record or map required by paragraph (a) of this section must be retained for as long as the pipeline remains in service.
- (c) Each operator shall maintain a record of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least 5 years with the following exceptions:

- (1) Operators must retain records related to §§ 192.465(a) and (e) and 192.475(b) for as long as the pipeline remains in service.
- (2) Operators must retain records of the two most recent atmospheric corrosion inspections for each distribution service line that is being inspected under the interval in §192.481(a)(2).

§ 192.493 In-Line Inspection of Pipelines

When conducting in-line inspections of pipelines required by this part, an operator must comply with API STD 1163, ANSI/ASNT ILI-PQ, and NACE SP0102, (incorporated by reference, *see* § 192.7). Assessments may be conducted using tethered or remotely controlled tools, not explicitly discussed in NACE SP0102, provided they comply with those sections of NACE SP0102 that are applicable.

SUBPART J - TEST REQUIREMENTS

§ 192.501 Scope

This subpart prescribes minimum leak-test and strength-test requirements for pipelines.

§ 192.503 General Requirements

- (a) No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until:
 - (1) It has been tested in accordance with this subpart and § 192.619 to substantiate the maximum allowable operating pressure; and
 - (2) Each detected leak has been eliminated.
- (b) The test medium must be liquid, air, natural gas, or inert gas that is:
 - (1) Compatible with the material of which the pipeline is constructed;
 - (2) Relatively free of sedimentary materials; and
 - (3) Except for natural gas, nonflammable.
- (c) Except as provided in § 192.505(a), if air, natural gas, or inert gas is used as the test medium, the following maximum hoop stress limitations apply:

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

- (d) Each joint used to tie-in a test segment of pipeline is excepted from the specific test requirements of this subpart, but each non-welded joint must be leak tested at not less than its operating pressure.
- (e) If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required, if the manufacturer of the component certifies that:
 - (1) The component was tested to at least the pressure required for the pipeline to which it is being added;
 - (2) The component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added; or
 - (3) The component carries a pressure rating established through applicable ASME/ANSI, Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS) specifications, or by unit strength calculations as described in § 192.143.

§ 192.505 Strength Test Requirements for Steel Pipeline to Operate at a Hoop Stress of 30 Percent or More of SMYS

- (a) Except for service lines, each segment of a steel pipeline that is to operate at a hoop stress of 30 percent or more of SMYS must be strength tested in accordance with this section to substantiate the proposed maximum allowable operating pressure. In addition, in a Class 1 or Class 2 location, if there is a building intended for human occupancy within 300 feet (91 meters) of a pipeline, a hydrostatic test must be conducted to a test pressure of at least 125 percent of maximum operating pressure on that segment of the pipeline within 300 feet (91 meters) of such a building, but in no event may the test section be less than 600 feet (183 meters) unless the length of the newly installed or relocated pipe is less than 600 feet (183 meters). However, if the buildings are evacuated while the hoop stress exceeds 50 percent of SMYS, air or inert gas may be used as the test medium.
- (b) In a Class 1 or Class 2 location, each compressor station, regulator station, and measuring station, must be tested to at least Class 3 location test requirements.
- (c) Except as provided in paragraph (d) of this section, the strength test must be conducted by maintaining the pressure at or above the test pressure for at least 8 hours.
- (d) For fabricated units and short sections of pipe, for which a post installation test is impractical, a preinstallation strength test must be conducted by maintaining the pressure at or above the test pressure for at least 4 hours.

§ 192.506 Transmission Lines: Spike Hydrostatic Pressure Test

- (a) *Spike test requirements.* Whenever a segment of steel transmission pipeline that is operated at a hoop stress level of 30 percent or more of SMYS is spike tested under this part, the spike hydrostatic pressure test must be conducted in accordance with this section.
 - (1) The test must use water as the test medium.
 - (2) The baseline test pressure must be as specified in the applicable paragraphs of § 192.619(a)(2) or § 192.620(a)(2), whichever applies.
 - (3) The test must be conducted by maintaining a pressure at or above the baseline test pressure for at least 8 hours as specified in § 192.505.
 - (4) After the test pressure stabilizes at the baseline pressure and within the first 2 hours of the 8-hour test interval, the hydrostatic pressure must be raised (spiked) to a minimum of the lesser of 1.5 times MAOP or 100% SMYS. This spike hydrostatic pressure test must be held for at least 15 minutes after the spike test pressure stabilizes.
- (b) Other technology or other technical evaluation process. Operators may use other technology, or another process supported by a documented engineering analysis for establishing a spike hydrostatic pressure test or equivalent. Operators must notify PHMSA 90 days in advance of the assessment or reassessment requirements of this subchapter. The notification must be made in accordance with § 192.18 and must include the following information:
 - (1) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments;
 - (2) Procedures and processes to conduct tests, examinations, assessments, perform evaluations, analyze defects, and remediate defects discovered;

- (3) Data requirements, including original design, maintenance and operating history, anomaly or flaw characterization;
- (4) Assessment techniques and acceptance criteria;
- (5) Remediation methods for assessment findings;
- (6) Spike hydrostatic pressure test monitoring and acceptance procedures, if used;
- (7) Procedures for remaining crack growth analysis and pipeline segment life analysis for the time interval for additional assessments, as required; and
- (8) Evidence of a review of all procedures and assessments by a qualified technical subject matter expert.

§ 192.507 Test Requirements for Pipelines to Operate at a Hoop Stress Less Than 30 Percent of SMYS and at or Above 100 P.S.I. (689 kPa) Gage

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage must be tested in accordance with the following:

- (a) The test procedure used must reasonably ensure discovery of leaks in the segment being tested.
- (b) If, during the test, the segment is to be stressed to 20 percent or more of SMYS and natural gas, inert gas, or air is the test medium:
 - (1) A leak test must be made at a pressure between 100 p.s.i. (689 kPa) gage and the pressure required to produce a hoop stress of 20 percent of SMYS; or
 - (2) The line must be walked to check for leaks while the hoop stress is held at approximately 20 percent of SMYS.
- (c) The pressure must be maintained at or above the test pressure for at least 1 hour.
- (d) For fabricated units and short sections of pipe, for which a post installation test is impractical, a pre-installation hydrostatic pressure test must be conducted in accordance with the requirements of this section.

§ 192.509 Test Requirements for Pipelines to Operate Below 100 P.S.I. (689 kPa) Gage

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated below 100 p.s.i.g. must be leak tested in accordance with the following:

- (a) The test procedure used must reasonably ensure discovery of leaks in the segment being tested.
- (b) Each main that is to be operated at less than 1 p.s.i. (6.9 kPa) gage must be tested to at least 10 p.s.i. (69 kPa) gage and each main to be operated at or above 1 p.s.i. (6.9 kPa) gage must be tested to at least 90 p.s.i. (621 kPa) gage.

§ 192.511 Test Requirements for Service Lines

- (a) Each segment of a service line (other than plastic) must be leak tested in accordance with this section before being placed in service. If feasible, the service line connection to the main must be included in the test; if not feasible, it must be given a leakage test at the operating pressure when placed in service.
- (b) Each segment of a service line (other than plastic) intended to be operated at pressure of less than 1 p.s.i. (6.9 kPa) gage shall be given a leak test at a pressure of 10 p.s.i. (69 kPa) gage. This test shall be conducted with a 3 inch (76 millimeters) dial gauge with a

maximum scale of 30 p.s.i. (207 kPa) gage. This test may be conducted with a mercury gauge capable of testing to 10 inches (254 millimeters) of mercury.

- (c) Each segment of a service line (other than plastic) intended to be operated at a pressure of at least 1 p.s.i. (6.9 kPa) gage but not more than 40 p.s.i. (276 kPa) gage must be given a leak test at a pressure of not less than 50 p.s.i. (345 kPa) gage on a 100 p.s.i. (689 kPa) gage scale gauge.
- (d) Each segment of a service line (other than plastic) intended to be operated at pressures of more than 40 p.s.i.g. must be tested to at least 90 p.s.i.g. on 100 p.s.i.g. scale gauge, except that each segment of a steel service line stressed to 20 percent or more of SMYS must be tested in accordance with § 192.507.
- (e) The test procedure used must reasonably ensure discovery of leaks in the segment being tested.

§ 192.513 Test Requirements for Plastic Pipelines

- (a) Each segment of a plastic pipeline must be tested in accordance with this section.
- (b) The test procedure used must reasonably ensure discovery of leaks in the segment being tested.
- (c) The test pressure must be at least 150% of the maximum operating pressure or 50 p.s.i. (345 kPa) gauge, whichever is greater. However, the maximum test pressure may not be more than 2.5 times the pressure determined under § 192.121, at a temperature not less than the pipe temperature during the test.
- (d) During the test, the temperature of thermoplastic material may not be more than 100°F (38°C), or the temperature at which the material's long-term hydrostatic strength has been determined under the listed specification, whichever is greater.

§ 192.515 Environmental Protection and Safety Requirements

- (a) In conducting tests under this subpart, each operator shall ensure that every reasonable precaution is taken to protect its employees and the general public during the testing. Whenever the hoop stress of the segment of the pipeline being tested will exceed 50 percent of SMYS, the operator shall take all practicable steps to keep persons not working on the testing operation outside of the testing area until the pressure is reduced to or below the proposed maximum allowable operating pressure.
- (b) The operator shall insure that the test medium is disposed of in a manner that will minimize damage to the environment.

§ 192.517 Records: Tests

- (a) Each operator must make and retain for the useful life of the pipeline, a record of each test performed under §§ 192.505, 192.507, and 192.507. The record must contain at least the following information:
 - (1) The operator's name, the name of the operator's employee responsible for making the test and the name of any test company used.
 - (2) Test medium used.
 - (3) Test pressure.
 - (4) Test duration.
 - (5) Pressure recording charts or other records of pressure readings.

- (6) Evaluation variations, whenever significant for the particular test.
- (7) Leaks and failures noted and their disposition.
- (b) Each operator must maintain a record of each test required by §§ 192.509, 192.511, and 192.513 for at least 5 years.

SUBPART K - UPRATING

§ 192.551 Scope

This subpart prescribes minimum requirements for increasing maximum allowable operating pressures (uprating) for pipelines.

§ 192.553 General Requirements

- (a) *Pressure increases.* Whenever the requirements of this subpart require that an increase in operating pressure be made in increments, the pressure must be increased gradually, at a rate that can be controlled, and in accordance with the following:
 - (1) At the end of each incremental increase, the pressure must be held constant while the entire segment of pipeline that is affected is checked for leaks.
 - (2) Each leak detected must be repaired before a further pressure increase is made, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous.
- (b) *Records.* Each operator who uprates a segment of pipeline shall retain for the life of the segment a record of each investigation required by this subpart, of all work performed, and of each pressure test conducted, in connection with the uprating.
- (c) *Written plan.* Each operator who uprates a segment of pipeline shall establish a written procedure that will ensure that each applicable requirement of this subpart is complied with.
- (d) *Limitation on increase in maximum allowable operating pressure.* Except as provided in § 192.555(c), a new maximum allowable operating pressure established under this subpart may not exceed the maximum that would be allowed under § 192.619 and 192.621 for a new segment of pipeline constructed of the same materials in the same location. However, when uprating a steel pipeline, if any variable necessary to determine the design pressure under the design formula (§ 192.105) is unknown, the MAOP may be increased as provided in § 192.619(a)(1).

§ 192.555 Uprating to a Pressure That Will Produce a Hoop Stress of 30 Percent or More of SMYS in Steel Pipelines

- (a) Unless the requirements of this section have been met, no person may subject any segment of a steel pipeline to an operating pressure that will produce a hoop stress of 30 percent or more of SMYS and that is above the established maximum allowable operating pressure.
- (b) Before increasing operating pressure above the previously established pressure the operator shall:
 - (1) Review the design, operating and maintenance history and previous testing of the segment of pipeline and determine whether the proposed increase is safe and consistent with the requirements of this part; and

- (2) Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure.
- (c) After complying with paragraph (b) of this section, an operator may increase the maximum allowable operating pressure of a segment of pipeline constructed before September 12, 1970, to the highest pressure that is permitted under § 192.619, using as test pressure the highest pressure to which the segment of pipeline was previously subjected (either in a strength test or in actual operation).
- (d) After complying with paragraph (b) of this section, an operator that does not qualify under paragraph (c) of this section may increase the previously established maximum allowable operating pressure if at least one of the following requirements is met:
 - (1) The segment of pipeline is successfully tested in accordance with the requirements of this part for a new line of the same material in the same location.
 - (2) An increased maximum allowable operating pressure may be established for a segment of pipeline in a Class 1 location if the line has not previously been tested, and if:
 - (i) It is impractical to test it in accordance with the requirements of this part;
 - (ii) The new maximum operating pressure does not exceed 80 percent of that allowed for a new line of the same design in the same location; and
 - (iii) The operator determines that the new maximum allowable operating pressure is consistent with the condition of the segment of pipeline and the design requirements of this part.
- (e) Where a segment of pipeline is uprated in accordance with paragraph (c) or (d)(2) of this section, the increase in pressure must be made in increments that are equal to:
 - (1) 10 percent of the pressure before the uprating; or
 - (2) 25 percent of the total pressure increase, whichever produces the fewer number of increments.

§ 192.557 Uprating Steel Pipelines to a Pressure That Will Produce a Hoop Stress Less Than 30 Percent of SMYS: Plastic, Cast Iron, and Ductile Iron Pipelines

- (a) Unless the requirements of this section have been met, no person may subject:
 - (1) A segment of steel pipeline to an operating pressure that will produce a hoop stress less than 30 percent of SMYS and that is above the previously established maximum allowable operating pressure; or
 - (2) A plastic, cast iron, or ductile iron pipeline segment to an operating pressure that is above the previously established maximum allowable operating pressure.
- (b) Before increasing operating pressure above the previously established maximum allowable operating pressure, the operator shall:
 - (1) Review the design, operating, and maintenance history of the segment of pipeline;
 - (2) Make a leakage survey (if it has been more than 1 year since the last survey) and repair any leaks that are found, except that a leak determined not to be potentially hazardous need not be repaired if it is monitored during the pressure increase and it does not become potentially hazardous;
 - (3) Make any repairs, replacements or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure;

- (4) Reinforce or anchor offsets, bends and dead ends in pipe joined by compression couplings or bell and spigot joints to prevent failure of the pipe joint, if the offset, bend or dead end is exposed in an excavation;
 - (5) Isolate the segment of pipeline in which the pressure is to be increased from any adjacent segment that will continue to be operated at a lower pressure; and
 - (6) If the pressure in mains or service lines, or both, is to be higher than the pressure delivered to the customer, install a service regulator on each service line and test each regulator to determine that it is functioning. Pressure may be increased as necessary to test each regulator, after a regulator has been installed on each pipeline subject to the increased pressure.
- (c) After complying with paragraph (b) of this section, the increase in maximum allowable operating pressure must be made in increments that are equal to 10 p.s.i. (69 kPa) gage or 25 percent of the total pressure increase, whichever produces the fewer number of increments. Whenever the requirements of paragraph (b)(6) of this section apply, there must be at least two approximately equal incremental increases.
- (d) If records for cast iron or ductile iron pipeline facilities are not complete enough to determine stresses produced by internal pressure, trench loading, rolling loads, beam stresses, and other bending loads, in evaluating the level of safety of the pipeline when operating at the proposed increased pressure, the following procedures must be followed:
- (1) In estimating the stresses, if the original laying conditions cannot be ascertained, the operator shall assume that cast iron pipe was supported on blocks with tamped backfill and that ductile iron pipe was laid without blocks with tamped backfill.
 - (2) Unless the actual maximum cover depth is known, the operator shall measure the actual cover in at least three places where the cover is most likely to be greatest and shall use the greatest cover measured.
 - (3) Unless the actual nominal wall thickness is known, the operator shall determine the wall thickness by cutting and measuring coupons from at least three separate pipe lengths. The coupons must be cut from pipe lengths in areas where the cover depth is most likely to be the greatest. The average of all measurements taken must be increased by the allowance indicated in the following table:

Pipe Size Inches (millimeters)	ALLOWANCE Inches (millimeters)		
	Cast Iron Pipe		
	Cast Iron Pipe		Ductile iron pipe
Pit Cast Pipe	Centrifugally Cast Pipe		
3-8 (76-203)	0.075(1.9)	0.065(1.6)	0.065(1.6)
10-12 (254 to 305)	0.08(2.03)	0.07(1.7)	0.07(1.7)
14-24 (356 to 610)	0.08(2.03)	0.08(2.0)	0.075(1.9)
30-42 (762 to 1067)	0.09(2.29)	0.09(2.2)	0.075(1.9)
48 (1219)	0.09(2.29)	0.09(2.2)	0.08(2.0)
54-60 (1372 to 1524)	0.09(2.29)	-----	-----

- (4) For cast iron pipe, unless the pipe manufacturing process is known, the operator

shall assume that the pipe is pit cast pipe with a bursting tensile strength of 11,000 p.s.i. (76 MPa) gage and a modulus of rupture of 31,000 p.s.i. (214 MPa) gage.

SUBPART L - OPERATIONS

§ 192.601 Scope

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

§ 192.603 General Provisions

- (a) No person may operate a segment of pipeline unless it is operated in accordance with this subpart.
- (b) Each operator shall keep records necessary to administer the procedures established under § 192.605.
- (c) The Administrator or the State Agency that has submitted a current certification under the pipeline safety laws (49 U.S.C. 60101 *et seq.*) with respect to the pipeline facility governed by an operator's plans and procedures may, after notice and opportunity for hearing as provided in 49 CFR 190.206 or the relevant State procedures, require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety.

§ 192.605 Procedural Manual for Operations, Maintenance, and Emergencies

- (a) *General.* Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year. This manual must be prepared before operations of a pipeline system commence. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.
- (b) *Maintenance and normal operations.* The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations:
 - (1) Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this subpart and subpart M of this part.
 - (2) Controlling corrosion in accordance with the operations and maintenance requirements of subpart I of this part.
 - (3) Making construction records, maps, and operating history available to appropriate personnel.
 - (4) Gathering of data needed for reporting incidents under Part 191 in a timely and effective manner.
 - (5) Starting up and shutting down any part of the pipeline in a manner designed to assure operation within the MAOP limits prescribed by this part, plus the build-up allowed for operation of pressure-limiting and control devices.

- (6) Maintaining compressor stations, including provisions for isolating units or sections of pipe and for purging before returning to service.
 - (7) Starting, operating and shutting down gas compressor units.
 - (8) Periodically reviewing the work done by operator personnel to determine the effectiveness, and adequacy of the procedures used in normal operation and maintenance and modifying the procedures when deficiencies are found.
 - (9) Taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas and making available when needed at the excavation emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.
 - (10) Systematic and routine testing and inspection of pipe-type or bottle-type holders including:
 - (i) Provision for detecting external corrosion before the strength of the container has been impaired;
 - (ii) Periodic sampling and testing of gas in storage to determine the dew point of vapors contained in the stored gas which, if condensed, might cause internal corrosion or interfere with the safe operation of the storage plant; and
 - (iii) Periodic inspection and testing of pressure limiting equipment to determine that it is in safe operating condition and has adequate capacity.
 - (11) Responding promptly to a report of a gas odor inside or near a building, unless the operator's emergency procedures under § 192.615(a)(3) specifically apply to these reports.
 - (12) Implementing the applicable control room management procedures required by § 192.631.
- (c) *Abnormal operations.* For transmission lines, the manual required by subparagraph (a) of this paragraph must include procedures for the following to provide safety when operating design limits have been exceeded:
- (1) Responding to, investigating, and correcting the cause of:
 - (i) Unintended closure of valves or shutdowns;
 - (ii) Increase or decrease in pressure or flow rate outside normal operating limits;
 - (iii) Loss of communications;
 - (iv) Operation of any safety device; and
 - (v) Any other foreseeable malfunction of a component, deviation from normal operation, or personnel error which may result in a hazard to persons or property.
 - (2) Checking variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation.
 - (3) Notifying responsible operator personnel when notice of an abnormal operation is received.
 - (4) Periodically reviewing the response of operator personnel to determine the

effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.

- (5) The requirements of this paragraph do not apply to natural gas distribution operators that are operating transmission lines in connection with their distribution system.
- (d) *Safety-related condition reports.* The manual required by subparagraph (a) of this paragraph must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of § 191.23.
- (e) *Surveillance, emergency response, and accident investigation.* The procedures required by §§ 192.613(a), 192.615, and 192.617 must be included in the manual required by paragraph (a) of this section.

§ 192.607 Verification Of Pipeline Material Properties And Attributes: Onshore Steel Transmission Pipelines.

- (a) *Applicability.* Wherever required by this part, operators of onshore steel transmission pipelines must document and verify material properties and attributes in accordance with this section.
- (b) *Documentation of material properties and attributes.* Records established under this section documenting physical pipeline characteristics and attributes, including diameter, wall thickness, seam type, and grade (e.g., yield strength, ultimate tensile strength, or pressure rating for valves and flanges, etc.), must be maintained for the life of the pipeline and be traceable, verifiable, and complete. Charpy v-notch toughness values established under this section needed to meet the requirements of the ECA method at § 192.624(c)(3) or the fracture mechanics requirements at § 192.712 must be maintained for the life of the pipeline.
- (c) *Verification of material properties and attributes.* If an operator does not have traceable, verifiable, and complete records required by paragraph (b) of this section, the operator must develop and implement procedures for conducting nondestructive or destructive tests, examinations, and assessments in order to verify the material properties of aboveground line pipe and components, and of buried line pipe and components when excavations occur at the following opportunities: Anomaly direct examinations, *in situ* evaluations, repairs, remediations, maintenance, and excavations that are associated with replacements or relocations of pipeline segments that are removed from service. The procedures must also provide for the following:
 - (1) For nondestructive tests, at each test location, material properties for minimum yield strength and ultimate tensile strength must be determined at a minimum of 5 places in at least 2 circumferential quadrants of the pipe for a minimum total of 10 test readings at each pipe cylinder location.
 - (2) For destructive tests, at each test location, a set of material properties tests for minimum yield strength and ultimate tensile strength must be conducted on each test pipe cylinder removed from each location, in accordance with API Specification 5L.
 - (3) Tests, examinations, and assessments must be appropriate for verifying the necessary material properties and attributes.
 - (4) If toughness properties are not documented, the procedures must include accepted industry methods for verifying pipe material toughness.

- (5) Verification of material properties and attributes for non-line pipe components must comply with paragraph (f) of this section.
- (d) *Special requirements for nondestructive methods.* Procedures developed in accordance with paragraph (c) of this section for verification of material properties and attributes using nondestructive methods must:
 - (1) Use methods, tools, procedures, and techniques that have been validated by a subject matter expert based on comparison with destructive test results on material of comparable grade and vintage;
 - (2) Conservatively account for measurement inaccuracy and uncertainty using reliable engineering tests and analyses; and
 - (3) Use test equipment that has been properly calibrated for comparable test materials prior to usage.
- (e) *Sampling multiple segments of pipe.* To verify material properties and attributes for a population of multiple, comparable segments of pipe without traceable, verifiable, and complete records, an operator may use a sampling program in accordance with the following requirements:
 - (1) The operator must define separate populations of similar segments of pipe for each combination of the following material properties and attributes: Nominal wall thicknesses, grade, manufacturing process, pipe manufacturing dates, and construction dates. If the dates between the manufacture or construction of the pipeline segments exceeds 2 years, those segments cannot be considered as the same vintage for the purpose of defining a population under this section. The total population mileage is the cumulative mileage of pipeline segments in the population. The pipeline segments need not be continuous.
 - (2) For each population defined according to paragraph (e)(1) of this section, the operator must determine material properties at all excavations that expose the pipe associated with anomaly direct examinations, *in situ* evaluations, repairs, remediations, or maintenance, except for pipeline segments exposed during excavation activities pursuant to § 192.614, until completion of the lesser of the following:
 - (i) One excavation per mile rounded up to the nearest whole number; or
 - (ii) 150 excavations if the population is more than 150 miles.
 - (3) Prior tests conducted for a single excavation according to the requirements of paragraph (c) of this section may be counted as one sample under the sampling requirements of this paragraph (e).
 - (4) If the test results identify line pipe with properties that are not consistent with available information or existing expectations or assumed properties used for operations and maintenance in the past, the operator must establish an expanded sampling program. The expanded sampling program must use valid statistical bases designed to achieve at least a 95% confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. Operators must notify PHMSA in advance of using an expanded sampling approach in accordance with § 192.18.

- (5) An operator may use an alternative statistical sampling approach that differs from the requirements specified in paragraph (e)(2) of this section. The alternative sampling program must use valid statistical bases designed to achieve at least a 95% confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. Operators must notify PHMSA in advance of using an alternative sampling approach in accordance with § 192.18.
- (f) **Components.** For mainline pipeline components other than line pipe, an operator must develop and implement procedures in accordance with paragraph (c) of this section for establishing and documenting the ANSI rating or pressure rating (in accordance with ASME/ANSI B16.5 (incorporated by reference, see § 192.7)),
 - (1) Operators are not required to test for the chemical and mechanical properties of components in compressor stations, meter stations, regulator stations, separators, river crossing headers, mainline valve assemblies, valve operator piping, or cross-connections with isolation valves from the mainline pipeline.
 - (2) Verification of material properties is required for non-line pipe components, including valves, flanges, fittings, fabricated assemblies, and other pressure retaining components and appurtenances that are:
 - (i) Larger than 2 inches in nominal outside diameter,
 - (ii) Material grades of 42,000 psi (Grade X-42) or greater, or
 - (iii) Appurtenances of any size that are directly installed on the pipeline and cannot be isolated from mainline pipeline pressures.
 - (3) Procedures for establishing material properties of non-line pipe components must be based on the documented manufacturing specification for the components. If specifications are not known, usage of manufacturer's stamped, marked, or tagged material pressure ratings and material type may be used to establish pressure rating. Operators must document the method used to determine the pressure rating and the findings of that determination.
- (g) **Up-rating.** The material properties determined from the destructive or nondestructive tests required by this section cannot be used to raise the grade or specification of the material, unless the original grade or specification is unknown and MAOP is based on an assumed yield strength of 24,000 psi in accordance with § 192.107(b)(2).

§ 192.609 Change in Class Location: Required Study

Whenever an increase in population density indicates a change in class location for a segment of an existing steel pipeline operating at hoop stress that is more than 40 percent of SMYS, or indicates that the hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location, the operator shall immediately make a study to determine:

- (a) The present class location for the segment involved;
- (b) The design, construction, and testing procedures followed in the original construction, and a comparison of these procedures with those required for the present class location by the applicable provisions of this part;
- (c) The physical condition of the segment to the extent it can be ascertained from available

records;

- (d) The operating and maintenance history of the segment;
- (e) The maximum actual operating pressure and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved; and
- (f) The actual area affected by the population density increase, and physical barriers or other factors which may limit further expansion of the more densely populated area.

§ 192.610 Change in class location: Change in valve spacing.

- (a) If a class location change on a transmission pipeline occurs after October 5, 2022, and results in pipe replacement, of 2 or more miles, in the aggregate, within any 5 contiguous miles within a 24-month period, to meet the maximum allowable operating pressure (MAOP) requirements in § 192.611, § 192.619, or § 192.620, then the requirements in §§ 192.179, 192.634, and 192.636, as applicable, apply to the new class location, and the operator must install valves, including rupture-mitigation valves (RMV) or alternative equivalent technologies, as necessary, to comply with those sections. Such valves must be installed within 24 months of the class location change in accordance with the timing requirement in § 192.611(d) for compliance after a class location change.
- (b) If a class location change on a gas transmission pipeline occurs after October 5, 2022, and results in pipe replacement of less than 2 miles within 5 contiguous miles during a 24-month period, to meet the MAOP requirements in § 192.611, § 192.619, or § 192.620, then within 24 months of the class location change, in accordance with § 192.611(d), the operator must either:
 - (1) Comply with the valve spacing requirements of § 192.179(a) for the replaced pipeline segment; or
 - (2) Install or use existing RMVs or alternative equivalent technologies so that the entirety of the replaced pipeline segments are between at least two RMVs or alternative equivalent technologies. The distance between RMVs and alternative equivalent technologies for the replaced segment must not exceed 20 miles. The RMVs and alternative equivalent technologies must comply with the applicable requirements of § 192.636.
- (c) The provisions of paragraph (b) of this section do not apply to pipeline replacements that amount to less than 1,000 feet within any one contiguous mile during any 24-month period.

§ 192.611 Change in Class Location: Confirmation or Revision of Maximum Allowable Operating Pressure

- (a) If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised according to one of the following requirements:
 - (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 the SMYS in Class 3 locations.
- (2) The maximum allowable operating pressure of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by this part for new segments of pipelines in the existing class location.
- (3) The segment involved must be tested in accordance with the applicable requirements of Subpart J of this part, and its maximum allowable operating pressure must then be established according to the following criteria:
 - (i) The maximum allowable operating pressure after the requalification test is 0.8 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.
- (b) The maximum allowable operating pressure confirmed or revised in accordance with this section, may not exceed the maximum allowable operating pressure established before the confirmation or revision.
- (c) Confirmation or revision of the maximum allowable operating pressure of a segment of pipeline in accordance with this section does not preclude the application of §§ 192.553 and 192.555.
- (d) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under § 192.609 must be completed within 24 months of the change in class location. Pressure reduction under paragraph (a) (1) or (2) of this section within the 24- month period does not preclude establishing a maximum allowable operating pressure under paragraph (a)(3) of this section at a later date.

§ 192.613 Continuing Surveillance

- (a) Each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.
- (b) If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment

involved, or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with §§ 192.619(a) and (b).

- (c) Following an extreme weather event or natural disaster that has the likelihood of damage to pipeline facilities by the scouring or movement of the soil surrounding the pipeline or movement of the pipeline, such as a named tropical storm or hurricane; a flood that exceeds the river, shoreline, or creek high-water banks in the area of the pipeline; a landslide in the area of the pipeline; or an earthquake in the area of the pipeline, an operator must inspect all potentially affected onshore transmission pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline.
 - (1) An operator must assess the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline in determining the appropriate method for performing the initial inspection to determine the extent of any damage and the need for the additional assessments required under this paragraph (c)(1).
 - (2) An operator must commence the inspection required by paragraph (c) of this section within 72 hours after the point in time when the operator reasonably determines that the affected area can be safely accessed by personnel and equipment, and the personnel and equipment required to perform the inspection as determined by paragraph (c)(1) of this section are available. If an operator is unable to commence the inspection due to the unavailability of personnel or equipment, the operator must notify the appropriate PHMSA Region Director and the Pipeline Safety Office Program Manager electronically via email as soon as practicable.
 - (3) An operator must take prompt and appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained as a result of performing the inspection required by paragraph (c) of this section. Such actions might include, but are not limited to:
 - (i) Reducing the operating pressure or shutting down the pipeline;
 - (ii) Modifying, repairing, or replacing any damaged pipeline facilities;
 - (iii) Preventing, mitigating, or eliminating any unsafe conditions in the pipeline right-of-way;
 - (iv) Performing additional patrols, surveys, tests, or inspections;
 - (v) Implementing emergency response activities with Federal, State, or local personnel; or
 - (vi) Notifying affected communities of the steps that can be taken to ensure public safety.

§ 192.614 Damage Prevention Program

- (a) Except as provided in paragraph (d) of this section, each operator of a buried pipeline must carry out, in accordance with this section, a written program to prevent damage to that pipeline from excavation activities. For the purpose of this section, the term "excavation activities" includes to dig, compress, or remove earth, rock, or other materials in or on the ground by use of mechanized equipment, tools manipulated only by human or animal power, or blasting, including without limitation augering, boring, backfilling, drilling, grading, pile-driving, plowing in, pulling in, trenching, tunneling, and plowing.
- (b) An operator may comply with any of the requirements of paragraph (c) of this section

through participation in a public service program, such as a one-call system, but such participation does not relieve the operator of responsibility for compliance with this section. However, an operator must perform the duties of paragraph (c)(3) of this section through participation in a one-call system, if that one-call system is a qualified one-call system. In areas that are covered by more than one qualified one-call system, an operator need only join one of the qualified one-call systems if there is a central telephone number for excavators to call for excavation activities, or if the one-call systems in those areas communicate with one another. An operator's pipeline system must be covered by a qualified one-call system where there is one in place. For the purpose of this section, a one-call system is considered a "qualified one-call system" if it meets the requirements of section (b)(1) or (b)(2) of this section.

- (1) The state has adopted a one-call damage prevention program under 49 CFR §198.37; or
 - (2) The one-call system:
 - (i) Is operated in accordance with 49 CFR §198.39;
 - (ii) Provides a pipeline operator an opportunity similar to a voluntary participant to have a part in management responsibilities; and
 - (iii) Assesses a participating pipeline operator a fee that is proportionate to the costs of the one-call system's coverage of the operator's pipeline.
- (c) The damage prevention program required by paragraph (a) of this section must, at a minimum:
- (1) Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.
 - (2) Provides for notification of the public in the vicinity of the pipeline and actual notification of the persons identified in paragraph (c)(1) of this section of the following as often as needed to make them aware of the damage prevention program:
 - (i) The program's existence and purpose; and
 - (ii) How to learn the location of underground pipelines before excavation activities are begun.
 - (3) Provide a means of receiving and recording notification of planned excavation activities.
 - (4) If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.
 - (5) Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.
 - (6) Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:
 - (i) The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline; and
 - (ii) In the case of blasting, any inspection must include leakage surveys.
- (d) Pipelines operated by persons other than municipalities (including operators of master meters) whose primary activity does not include the transportation of gas need not comply

with the following:

- (1) The requirement of paragraph (a) of this section that the damage prevention program be written; and
- (2) The requirements of paragraphs (c)(1) and (c)(2) of this section.

§ 192.615 Emergency Plans

- (a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:
 - (1) Receiving, identifying, and classifying notices of events which require immediate response by the operator.
 - (2) Establishing and maintaining adequate means of communication with the appropriate public safety answering point (i.e., 9-1-1 emergency call center), where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, and fire, police, and other public officials. Operators may establish liaison with the appropriate local emergency coordinating agencies, such as 9-1-1 emergency call centers or county emergency managers, in lieu of communicating individually with each fire, police, or other public entity. An operator must determine the responsibilities, resources, jurisdictional area(s), and emergency contact telephone number(s) for both local and out-of-area calls of each Federal, State, and local government organization that may respond to a pipeline emergency, and inform such officials about the operator's ability to respond to a pipeline emergency and the means of communication during emergencies.
 - (3) Prompt and effective response to a notice of each type of emergency, including the following:
 - (i) Gas detected inside or near a building.
 - (ii) Fire located near or directly involving a pipeline facility.
 - (iii) Explosion occurring near or directly involving a pipeline facility.
 - (iv) Natural disaster.
 - (4) The availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency.
 - (5) Actions directed toward protecting people first and then property.
 - (6) Taking necessary actions, including but not limited to, emergency shutdown, valve shut-off, or pressure reduction, in any section of the operator's pipeline system, to minimize hazards of released gas to life, property, or the environment.
 - (7) Making safe any actual or potential hazard to life or property.
 - (8) Notifying the appropriate public safety answering point (i.e., 9-1-1 emergency call center) where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, and fire, police, and other public officials, of gas pipeline emergencies to coordinate and share information to determine the location of the emergency, including both planned responses and actual responses during an emergency. The operator must immediately and directly notify the appropriate public safety answering point or other coordinating agency for the communities and jurisdictions in which the pipeline is located after receiving a notification of potential rupture, as defined in § 192.3, to coordinate and share information to determine the location of any release, regardless of whether the segment is subject to the

requirements of § 192.179, § 192.634, or § 192.636.

- (9) Safely restoring any service outage.
 - (10) Beginning action under § 192.617, if applicable, as soon after the end of the emergency as possible.
 - (11) Actions required to be taken by a controller during an emergency in accordance with the operator's emergency plans and requirements set forth in §§ 192.631, 192.634, and 192.636.
 - (12) Each operator must develop written rupture identification procedures to evaluate and identify whether a notification of potential rupture, as defined in § 192.3, is an actual rupture event or a non-rupture event. These procedures must, at a minimum, specify the sources of information, operational factors, and other criteria that operator personnel use to evaluate a notification of potential rupture and identify an actual rupture. For operators installing valves in accordance with § 192.179(e), § 192.179(f), or that are subject to the requirements in § 192.634, those procedures must provide for rupture identification as soon as practicable.
 - (13) Train the appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and verify that the training is effective.
 - (14) Review employee activities to determine whether the procedures were effectively followed in each emergency.
- (b) Each operator shall:
- (1) Furnish its supervisors who are responsible for emergency action a copy of that portion of the latest edition of the emergency procedures established under paragraph (a) of this section as necessary for compliance with those procedures.
 - (2) Train the appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and verify that the training is effective.
 - (3) Review employee activities to determine whether the procedures were effectively followed in each emergency.
- (c) Each operator must establish and maintain liaison with the appropriate public safety answering point (i.e., 9-1-1 emergency call center) where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, as well as fire, police, and other public officials, to:
- (1) Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency;
 - (2) Acquaint the officials with the operator's ability in responding to a gas pipeline emergency;
 - (3) Identify the types of gas pipeline emergencies of which the operator notifies the officials; and
 - (4) Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property.
- (d)(1) Each operator shall identify all key valves which may be necessary for the safe operation of the system. The location of these valves shall be designated on appropriate

records, drawings, or maps.

- (2) As used in subdivision (e)(1) of this section, “key valves” means shut off valves in a distribution system or transmission line which may be necessary to isolate segments of a system or line for emergency purposes.

§ 192.616 Public Awareness

- (a) Except for an operator of a master meter or petroleum gas system covered under paragraph (j) of this section, each pipeline operator must develop and implement a written continuing public education program that follows the guidance provided in the American Petroleum (API) Recommended Practice (RP) 1162 (incorporated by reference, see § 192.7).
- (b) The operator’s program must follow the general program recommendations of API RP 1162 and assess the unique attributes and characteristics of the operator’s pipeline and facilities.
- (c) The operator must follow the general program recommendations, including baseline and supplemental requirements of API RP 1162, unless the operator provides justification in its program or procedural manual as to why compliance with all or certain provisions of the recommended practice is not practicable and not necessary for safety.
- (d) The operator’s program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on:
- (1) Use of a one-call notification system prior to excavation and other damage prevention activities;
 - (2) Possible hazards associated with unintended releases from a gas pipeline facility;
 - (3) Physical indications that such a release may have occurred;
 - (4) Steps that should be taken for public safety in the event of a gas pipeline release; and
 - (5) Procedures for reporting such an event.
- (e) The program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations.
- (f) The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports gas.
- (g) The program must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator’s area.
- (h) Operators in existence on June 20, 2005, must have completed their written programs no later than June 20, 2006. The operator of a master meter or petroleum gas system covered under paragraph (j) of this section must complete development of its written procedure by June 13, 2008. Upon request, operators must submit their completed programs to PHMSA or, in the case of an intrastate pipeline facility operator, the appropriate State agency.
- (i) The operator’s program documentation and evaluation results must be available for periodic review by appropriate regulatory agencies.
- (j) Unless the operator transports gas as a primary activity, the operator of a master meter or petroleum gas system is not required to develop a public awareness program as prescribed in paragraphs (a) through (g) of this section. Instead, the operator must develop

and implement a written procedure to provide its customers public awareness messages twice annually. If the master meter or petroleum gas system is located on property the operator does not control, the operator must provide similar messages twice annually to persons controlling the property. The public awareness message must include:

- (1) A description of the purpose and reliability of the pipeline;
- (2) An overview of the hazards of the pipeline and prevention measures used;
- (3) Information about damage prevention;
- (4) How to recognize and respond to a leak; and
- (5) How to get additional information.

§ 192.617 Investigation of Failures

- (a) *Post-failure and incident procedures.* Each operator must establish and follow procedures for investigating and analyzing failures and incidents as defined in § 191.3, including sending the failed pipe, component, or equipment for laboratory testing or examination, where appropriate, for the purpose of determining the causes and contributing factor(s) of the failure or incident and minimizing the possibility of a recurrence.
- (b) *Post-failure and incident lessons learned.* Each operator of a transmission or distribution pipeline must develop, implement, and incorporate lessons learned from a post-failure or incident review into its written procedures, including personnel training and qualification programs; and design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications.
- (c) *Analysis of rupture and valve shutoffs.* If an incident on an onshore gas transmission pipeline involves the closure of a rupture-mitigation valve (RMV), as defined at § 192.3, or the closure of alternative equivalent technology, the operator of the pipeline must also conduct a post-incident analysis of all of the factors that may have impacted the release volume and the consequences of the incident and identify and implement operations and maintenance measures to prevent or minimize the consequences of a future incident. The requirements of this paragraph (c) are not applicable to gas distribution or gas gathering pipelines. The analysis must include all relevant factors impacting the release volume and consequences, including, but not limited to, the following:
 - (1) Detection, identification, operational response, system shut-off, and emergency response communications, based on the type and volume of the incident;
 - (2) Appropriateness and effectiveness of procedures and pipeline systems, including supervisory control and data acquisition (SCADA), communications, valve shut-off, and operator personnel;
 - (3) Actual response time from identifying a rupture following a notification of potential rupture, as defined at § 192.3, to initiation of mitigative actions and isolation of the pipeline segment, and the appropriateness and effectiveness of the mitigative actions taken;
 - (4) Location and timeliness of actuation of RMVs or alternative equivalent

technologies; and

- (5) All other factors the operator deems appropriate.
- (d) *Rupture post-failure and incident summary.* If a failure or incident on an onshore gas transmission pipeline involves the identification of a rupture following a notification of potential rupture, or the closure of an RMV (as those terms are defined at § 192.3), or the closure of an alternative equivalent technology, the operator of the pipeline must complete a summary of the post-failure or incident review required by paragraph (c) of this section within 90 days of the incident, and while the investigation is pending, conduct quarterly status reviews until the investigation is complete and a final post-incident summary is prepared. The final post-failure or incident summary, and all other reviews and analyses produced under the requirements of this section, must be reviewed, dated, and signed by the operator's appropriate senior executive officer. The final post-failure or incident summary, all investigation and analysis documents used to prepare it, and records of lessons learned must be kept for the useful life of the pipeline. The requirements of this paragraph (d) are not applicable to gas distribution or gas gathering pipelines.

§ 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 (MAOP) determined under paragraph (c), (d), or (e) of this section, or the lowest of the following:
- (1) The design pressure of the weakest element in the segment, determined in accordance with Subparts C and D of this part. However, for steel pipe in pipelines being converted under § 192.14 or updated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§ 192.105) is unknown, one of the following pressures is to be used as design pressure:
- (i) Eighty percent of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8 (incorporated by reference, see § 192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or
 - (ii) If the pipe is 12 3/4 in. (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).
- (2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:
- (i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.
 - (ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the Table 1 to paragraph (a)(2)(ii):

Table 1 to Paragraph (a)(2)(ii)

Class location	Installed before (Nov. 12, 1970)	Factors, ^{1,2} segment -		
		Installed after (Nov. 11, 1970) and before July 1, 2020	Installed on or after July 1, 2020	Converted under § 192.14
1	1.1	1.1	1.25	1.25
2	1.25	1.25	1.25	1.25
3	1.4	1.5	1.5	1.5
4	1.4	1.5	1.5	1.5

- (3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	Pressure Date	Test Date
(i) Onshore regulated gathering pipeline (Type A or Type B under § 192.9(d)) that first became subject to this part (other than § 192.612) after April 13, 2006	March 15, 2006, or date pipeline becomes subject to this part, whichever is later	5 years preceding applicable date in second column.
(ii) Onshore regulated gathering pipeline (Type C under § 192.9(d)) that first became subject to this part (other than § 192.612) on or after May 16, 2022	May 16, 2023, or date pipeline becomes subject to this part, whichever is later	5 years preceding applicable date in second column.
(iii) Onshore transmission pipeline that was a gathering	March 15, 2006, or date pipeline becomes	5 years preceding applicable date in second column.

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

² For a component with a design pressure established in accordance with § 192.153(a) or (b) installed after July 14, 2004, the factor is 1.3.

pipeline not subject to this part before March 15, 2006	subject to this part, whichever is later	
(iv) Offshore gathering pipelines	July 1, 1976	July 1, 1971
(v) All other pipelines	July 1, 1970	July 1, 1965

- (4) The pressure determined by the operator to be the maximum safe pressure after considering and accounting for records of material properties, including material properties verified in accordance with §192.607, if applicable, and the history of the pipeline segment, including known corrosion and the actual operating pressure.
- (b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with § 192.195.
- (c) The requirements on pressure restrictions in this section do not apply in the following instances:
- (1) An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with § 192.611.
 - (2) For any Type C gas gathering pipeline under § 192.9 existing on or before May 16, 2022, that was not previously subject to this part and the operator cannot determine the actual operating pressure of the pipeline for the 5 years preceding May 16, 2023, the operator may establish MAOP using other criteria based on a combination of operating conditions, other tests, and design with approval from PHMSA and the Pipeline Safety Office. The operator must notify PHMSA and the Pipeline Safety Office in accordance with § 192.18. The notifications must include the following information:
 - (i) The proposed MAOP of the pipeline;
 - (ii) Description of pipeline segment for which alternate methods are used to establish MAOP, including diameter, wall thickness, pipe grade, seam type, location, endpoints, other pertinent material properties, and age;
 - (iii) Pipeline operating data, including operating history and maintenance history;
 - (iv) Description of methods being used to establish MAOP;
 - (v) Technical justification for use of the methods chosen to establish MAOP; and
 - (vi) Evidence of review and acceptance of the justification by a qualified technical subject matter expert.
- (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).

- (e) Notwithstanding the requirements in paragraphs (a) through (d) of this section, operators of onshore steel transmission pipelines that meet the criteria specified in §192.624(a) must establish and document the maximum allowable operating pressure in accordance with §192.624.
- (f) Operators of onshore steel transmission pipelines must make and retain records necessary to establish and document the MAOP of each pipeline segment in accordance with paragraphs (a) through (e) of this section as follows:
 - (1) Operators of pipelines in operation as of July 1, 2020 must retain any existing records establishing MAOP for the life of the pipeline;
 - (2) Operators of pipelines in operation as of July 1, 2020 that do not have records establishing MAOP and are required to reconfirm MAOP in accordance with §192.624, must retain the records reconfirming MAOP for the life of the pipeline; and
 - (3) Operators of pipelines placed in operation after July 1, 2020 must make and retain records establishing MAOP for the life of the pipeline.
- (g) The maximum allowable operating pressure shall be designated following the above procedures and posted on system maps, drawings, regulator stations or other appropriate records.

§ 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	1.50 ³
3	1.50

(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) *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) For pipelines already in service, notify each PHMSA pipeline safety regional office where the pipeline is in service of the intention to use the alternative pressure at

³ For Class 2 alternative maximum allowable operating pressure segments installed prior to December 22, 2008 the alternative test factor is 1.25.

least 180 days before operating at the alternative MAOP. For new pipelines, notify the PHMSA pipeline safety regional office of planned alternative MAOP design and operation at least 60 days prior to the earliest start date of either pipe manufacturing or construction activities. An operator must also notify a state pipeline safety authority when the pipeline is located in a state where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that state.

- (2) Certify, by signature of a senior executive officer of the company, as follows:
 - (i) The pipeline segment meets the conditions described in paragraph (b) of this section; and
 - (ii) The operating and maintenance procedures include the additional operating and maintenance requirements of paragraph (d) of this section; and
 - (iii) The review and any needed program upgrade of the damage prevention program required by paragraph (d)(4)(v) of this section has been completed.
 - (3) Send a copy of the certification required by paragraph (c)(2) of this section to each PHMSA pipeline safety regional office where the pipeline is in service 30 days prior to operating at the alternative MAOP. An operator must also send a copy to a state pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.
 - (4) For each pipeline segment, do one of the following:
 - (i) Perform a strength test as described in § 192.505 at a test pressure calculated under paragraph (a) of this section or
 - (ii) For a pipeline segment in existence prior to December 22, 2008, certify, under paragraph (c)(2) of this section, that the strength test performed under § 192.505 was conducted at test pressure calculated under paragraph (a) of this section, or conduct a new strength test in accordance with paragraph (c)(4)(i) of this section.
 - (5) Comply with the additional operation and maintenance requirements described in paragraph (d) of this section.
 - (6) If the performance of a construction task associated with implementing alternative MAOP that occurs after December 22, 2008, can affect the integrity of the pipeline segment, treat that task as a “covered task”, notwithstanding the definition in § 192.801(b) and implement the requirements of subpart N as appropriate.
 - (7) Maintain, for the useful life of the pipeline, records demonstrating compliance with paragraphs (b), (c)(6), and (d) of this section.
 - (8) A Class 1 and Class 2 location can be upgraded one class due to class changes per § 192.611(a). 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:

<p>To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:</p>	<p>Take the following additional step:</p>
<p>(1) Identifying and evaluating threats</p>	<p>Develop a threat matrix consistent with § 192.917 to do the following:</p> <p>(i) Identify and compare the increased risk of operating the pipeline at the increased stress level under this section with conventional operation; and</p> <p>(ii) Describe and implement procedures used to mitigate the risk.</p>
<p>(2) Notifying the public</p>	<p>(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</p> <p>(ii) In implementing the public education program required under § 192.616, perform the following:</p> <p>(A) Include persons occupying property within 220 yards of the centerline and within the potential impact circle within the targeted audience; and</p> <p>(B) Include information about the integrity management activities performed under this section within the message provided to the audience.</p>
<p>(3) Responding to an emergency in an area defined as a high consequence area in § 192.903</p>	<p>(i) Ensure that the identification of high consequence areas reflects the larger potential impact circle recalculated under paragraph (d)(2)(i) of this section.</p> <p>(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</p>

	<p>data acquisition (SCADA) system, other leak detection system, or an alternative method of control.</p>
	<p>(iii) Remote valve control must include the ability to close and monitor the valve position (open or closed), and monitor pressure upstream and downstream.</p>
	<p>(iv) A line break valve control system using differential pressure, rate of pressure drop or other widely-accepted method is an acceptable alternative to remote valve control.</p>
<p>(4) Protecting the right-of-way</p>	<p>(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.</p>
	<p>(ii) Develop and implement a plan to monitor for and mitigate occurrences of unstable soil and ground movement.</p>
	<p>(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.</p>
	<p>(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.</p>
	<p>(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.</p>
	<p>(vi) Develop and implement a right-of-way management plan to protect the pipeline segment from damage due to excavation activities.</p>

(5) Controlling internal corrosion	(i) Develop and implement a program to monitor for and mitigate the presence of deleterious gas stream constituents.
	(ii) At points where gas with potentially deleterious contaminants enters the pipeline, use filter separators or separators and gas quality monitoring equipment.
	(iii) Use gas quality monitoring equipment that includes a moisture analyzer, chromatograph, and periodic hydrogen sulfide sampling.
	(iv) Use cleaning pigs and sample accumulated liquids. Use inhibitors when corrosive gas or liquids are present.
	(v) Address deleterious gas stream constituents as follows:
	(A) Limit carbon dioxide to 3 percent by volume;
	(B) Allow no free water and otherwise limit water to seven pounds per million cubic feet of gas; and
	(C) Limit hydrogen sulfide to 1.0 grain per hundred cubic feet (16 ppm) of gas, where the hydrogen sulfide is greater than 0.5 grain per hundred cubic feet (8 ppm) of gas, implement a pigging and inhibitor injection program to address deleterious gas stream constituents, including follow-up sampling and quality testing of liquids at receipt points.
(vi) Review the program at least quarterly based on the gas stream experience and implement adjustments to monitor for, and mitigate the presence of, deleterious gas stream constituents.	
(6) Controlling interference that can impact external corrosion	(i) Prior to operating an existing pipeline segment at an alternate maximum allowable operating pressure calculated under this section, or within six months after placing a new pipeline segment in service at an alternate maximum allowable operating pressure calculated under this section, address any interference currents on the pipeline segment.
	(ii) To address interference currents, perform the following:
	(A) Conduct an interference survey to detect the presence and level of any electrical current

	that could impact external corrosion where interference is suspected;
	(B) Analyze the results of the survey; and
	(C) Take any remedial action needed within 6 months after completing the survey to protect the pipeline segment from deleterious current.
(7) Confirming external corrosion control through indirect assessment	(i) Within six months after placing the cathodic protection of a new pipeline segment in operation, or within six months after certifying a segment under § 192.620(c)(1) of an existing pipeline segment under this section, assess the adequacy of the cathodic protection through an indirect method such as close-interval survey, and the integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG).
	(ii) Remediate any construction damaged coating with a voltage drop classified as moderate or severe (IR drop greater than 35% for DCVG or 50 dB μ v for ACVG) under section 4 of NACE RP-0502-2002 (incorporated by reference, see § 192.7).
	(iii) Within six months after completing the baseline internal inspection required under paragraph (d)(9) of this section, integrate the results of the indirect assessment required under paragraph (d)(7)(i) of this section with the results of the baseline internal inspection and take any needed remedial actions.
	(iv) For all pipeline segments in high consequence areas, perform periodic assessments as follows:
	(A) Conduct periodic close interval surveys with current interrupted to confirm voltage drops in association with periodic assessments under subpart O of this part.
	(B) Locate pipe-to-soil test stations at half-mile intervals within each high consequence area ensuring at least one station is within each high consequence area, if practicable.
	(C) Integrate the results with those of the baseline and periodic assessments for integrity done under paragraphs (d)(9) and (d)(10) of this section.

(8) Controlling external corrosion through cathodic protection	(i) If an annual test station reading indicates cathodic protection below the level of protection required in subpart I of this part, complete remedial action within six months of the failed reading or notify each PHMSA pipeline safety regional office where the pipeline is in service demonstrating that the integrity of the pipeline is not compromised if the repair takes longer than 6 months. An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State; and
	(ii) After remedial action to address a failed reading, confirm restoration of adequate corrosion control by a close interval survey on either side of the affected test station to the next test station unless the reason for the failed reading is determined to be a rectifier connection or power input problem that can be remediated and otherwise verified.
	(iii) If the pipeline segment has been in operation, the cathodic protection system on the pipeline segment must have been operational within 12 months of the completion of construction.
(9) Conducting a baseline assessment of integrity	(i) Except as provided in paragraph (d)(9)(iii) of this section, for a new pipeline segment operating at the new alternative maximum allowable operating pressure, perform a baseline internal inspection of the entire pipeline segment as follows:
	(A) Assess using a geometry tool after the initial hydrostatic test and backfill and within six months after placing the new pipeline segment in service; and
	(B) Assess using a high resolution magnetic flux tool within three years after placing the new pipeline segment in service at the alternative maximum allowable operating pressure.
	(ii) Except as provided in paragraph (d)(9)(iii) of this section, for an existing pipeline segment, perform a baseline internal assessment using a geometry tool and a high resolution magnetic flux tool before, but within two years prior to, raising

	<p>pressure to the alternative maximum allowable operating pressure as allowed under this section.</p> <p>(iii) If headers, mainline valve by-passes, compressor station piping, meter station piping, or other short portion of a pipeline segment operating at alternative maximum allowable operating pressure cannot accommodate a geometry tool and a high resolution magnetic flux tool, use direct assessment (per § 192.925, § 192.927 and/or § 192.929) or pressure testing (per subpart J of this part) to assess that portion.</p>
(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
	(ii) Repair a defect immediately if any of the following apply:
	(A) The defect is a dent discovered during the baseline assessment for integrity under paragraph (d)(9) of this section and the defect meets the criteria for immediate repair in § 192.309(b).
	(B) The defect meets the criteria for immediate repair in § 192.933(d).

	(C) The alternative maximum allowable operating pressure was based on a design factor of 0.67 under paragraph (a) of this section and the failure pressure is less than 1.25 times the alternative maximum allowable operating pressure.
	(D) The alternative maximum allowable operating pressure was based on a design factor of 0.56 under paragraph (a) of this section and the failure pressure is less than or equal to 1.4 times the alternative maximum allowable operating pressure.
	(iii) If paragraph (d)(11)(ii) of this section does not require immediate repair, repair a defect within one year if any of the following apply:
	(A) The defect meets the criteria for repair within one year in § 192.933(d).
	(B) The alternative maximum allowable operating pressure was based on a design factor of 0.80 under paragraph (a) of this section and the failure pressure is less than 1.25 times the alternative maximum allowable operating pressure.
	(C) The alternative maximum allowable operating pressure was based on a design factor of 0.67 under paragraph (a) of this section and the failure pressure is less than 1.50 times the alternative maximum allowable operating pressure.
	(D) The alternative maximum allowable operating pressure was based on a design factor of 0.56 under paragraph (a) of this section and the failure pressure is less than or equal to 1.80 times the alternative maximum allowable operating pressure.
	(iv) Evaluate any defect not required to be repaired under paragraph (d)(11)(ii) or (iii) of this section to determine its growth rate, set the maximum interval for repair or re-inspection, and repair or re-inspect within that interval.

(e) *Is there any change in overpressure protection associated with operating at the alternative maximum allowable operating pressure? Notwithstanding the required*

capacity of pressure relieving and limiting stations otherwise required by § 192.201, if an operator establishes a maximum allowable operating pressure for a pipeline segment in accordance with paragraph of this section, an operator must:

- (1) Provide overpressure protection that limits mainline pressure to a maximum of 104 percent of the maximum allowable operating pressure; and
- (2) Develop and follow a procedure for establishing and maintaining accurate set points for the supervisory control and data acquisition system.

§ 192.621 Maximum Allowable Operating Pressure: High-Pressure Distribution Systems

- (a) No person may operate a segment of a high-pressure distribution system at a pressure that exceeds the lowest of the following pressures, as applicable:
 - (1) The design pressure of the weakest element in the segment, determined in accordance with Subparts C and D of this part.
 - (2) 60 p.s.i. (414 kPa) gage for a segment of a distribution system otherwise designed to operate at over 60 p.s.i. (414 kPa) gage, unless the service lines in the segment are equipped with service regulators or other pressure limiting devices in series that meet the requirements of § 192.197(c).
 - (3) 25 p.s.i. (172 kPa) gage in segments of cast iron pipe in which there are unreinforced bell and spigot joints.
 - (4) The pressure limits to which a joint could be subjected without the possibility of its parting.
 - (5) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressures.
- (b) No person may operate a segment of pipeline to which paragraph (a)(5) of this section applies, unless overpressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with § 192.195.
- (c) The maximum allowable operating pressure shall be designated following the above procedures and posted on system maps, drawings, regulator stations or other appropriate records.

§ 192.622 Maximum Actual Operating Pressure: High-Pressure Distribution Systems

- (a) Each operator shall establish a maximum actual operating pressure if the actual operating pressure is less than the established maximum allowable operating pressure. The maximum actual operating pressure will be the pressure for orifice sizing in customer regulators as required by § 192.197. The maximum actual operating pressure may be increased to a pressure not exceeding the maximum allowable operating pressure during emergency operating conditions. Normal seasonal gas demands are not considered emergency operating conditions. Upon termination of the emergency the pressure must be reduced to a pressure not exceeding the established maximum actual operating pressure. The maximum actual operating pressure shall be posted on system maps, drawings, regulator stations or other appropriate records.
- (b) Before increasing the established maximum actual operating pressure, under normal conditions, the operator shall:

- (1) Calculate the rated capability of each overpressure control device installed at each customer's service.
- (2) If the overpressure control device is not capable of maintaining a safe pressure to the customer's gas utilization equipment, a new or additional device must be installed to provide a safe pressure to the customer.

§ 192.623 Maximum and Minimum Allowable Operating Pressure: Low-Pressure Distribution Systems

- (a) No person may operate a low-pressure distribution system at a pressure high enough to make unsafe the operation of any connected and properly adjusted low-pressure gas burning equipment.
- (b) No person may operate a low-pressure distribution system at a pressure lower than the minimum pressure at which the safe and continuing operation of any connected and properly adjusted low-pressure gas burning equipment can be assured.

§ 192.624 Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines

- (a) *Applicability.* Operators of onshore steel transmission pipeline segments must reconfirm the maximum allowable operating pressure (MAOP) of all pipeline segments in accordance with the requirements of this section if either of the following conditions are met:
 - (1) Records necessary to establish the MAOP in accordance with § 192.619(a)(2), including records required by § 192.517(a), are not traceable, verifiable, and complete and the pipeline is located in one of the following locations:
 - (i) A high consequence area as defined in § 192.903; or
 - (ii) A Class 3 or Class 4 location.
 - (2) The pipeline segment's MAOP was established in accordance with § 192.619(c), the pipeline segment's MAOP is greater than or equal to 30 percent of the specified minimum yield strength, and the pipeline segment is located in one of the following areas:
 - (i) A high consequence area as defined in § 192.903;
 - (ii) A Class 3 or Class 4 location; or
 - (iii) A moderate consequence area as defined in § 192.3, if the pipeline segment can accommodate inspection by means of instrumented inline inspection tools.
- (b) *Procedures and completion dates.* Operators of a pipeline subject to this section must develop and document procedures for completing all actions required by this section by July 1, 2021. These procedures must include a process for reconfirming MAOP for any pipelines that meet a condition of § 192.624(a), and for performing a spike test or material verification in accordance with §§ 192.506 and 192.607, if applicable. All actions required by this section must be completed according to the following schedule:
 - (1) Operators must complete all actions required by this section on at least 50% of the pipeline mileage by July 3, 2028.
 - (2) Operators must complete all actions required by this section on 100% of the pipeline mileage by July 2, 2035 or as soon as practicable, but not to exceed 4 years after the pipeline segment first meets a condition of § 192.624(a) (e.g., due

to a location becoming a high consequence area), whichever is later.

- (3) If operational and environmental constraints limit an operator from meeting the deadlines in § 192.624, the operator may petition for an extension of the completion deadlines by up to 1 year, upon submittal of a notification in accordance with § 192.18. The notification must include an up-to-date plan for completing all actions in accordance with this section, the reason for the requested extension, current status, proposed completion date, outstanding remediation activities, and any needed temporary measures needed to mitigate the impact on safety.
- (c) *Maximum allowable operating pressure determination.* Operators of a pipeline segment meeting a condition in paragraph (a) of this section must reconfirm its MAOP using one of the following methods:
- (1) *Method 1: Pressure test.* Perform a pressure test and verify material properties records in accordance with § 192.607 and the following requirements:
 - (i) *Pressure test.* Perform a pressure test in accordance with subpart J of this part. The MAOP must be equal to the test pressure divided by the greater of either 1.25 or the applicable class location factor in § 192.619(a)(2)(ii).
 - (ii) *Material properties records.* Determine if the following material properties records are documented in traceable, verifiable, and complete records: Diameter, wall thickness, seam type, and grade (minimum yield strength, ultimate tensile strength).
 - (iii) *Material properties verification.* If any of the records required by paragraph (c)(1)(ii) of this section are not documented in traceable, verifiable, and complete records, the operator must obtain the missing records in accordance with § 192.607. An operator must test the pipe materials cut out from the test manifold sites at the time the pressure test is conducted. If there is a failure during the pressure test, the operator must test any removed pipe from the pressure test failure in accordance with § 192.607.
 - (2) *Method 2: Pressure Reduction.* Reduce pressure, as necessary, and limit MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by the greater of 1.25 or the applicable class location factor in § 192.619(a)(2)(ii). The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during a continuous 30-day period. The value used as the highest actual sustained operating pressure must account for differences between upstream and downstream pressure on the pipeline by use of either the lowest maximum pressure value for the entire pipeline segment or using the operating pressure gradient along the entire pipeline segment (*i.e.*, the location-specific operating pressure at each location).
 - (i) Where the pipeline segment has had a class location change in accordance with § 192.611, and records documenting diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), and pressure tests are not documented in traceable, verifiable, and complete records, the operator must reduce the pipeline segment MAOP as follows:
 - (A) For pipeline segments where a class location changed from Class 1 to Class 2, from Class 2 to Class 3, or from Class 3 to Class 4, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years

preceding October 1, 2019, divided by 1.39 for Class 1 to Class 2, 1.67 for Class 2 to Class 3, and 2.00 for Class 3 to Class 4.

- (B) For pipeline segments where a class location changed from Class 1 to Class 3, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by 2.00.
- (ii) Future uprating of the pipeline segment in accordance with subpart K is allowed if the MAOP is established using Method 2.
- (iii) If an operator elects to use Method 2, but desires to use a less conservative pressure reduction factor or longer look-back period, the operator must notify PHMSA in accordance with § 192.18 no later than 7 calendar days after establishing the reduced MAOP. The notification must include the following details:
 - (A) Descriptions of the operational constraints, special circumstances, or other factors that preclude, or make it impractical, to use the pressure reduction factor specified in § 192.624(c)(2);
 - (B) The fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis that complies with § 192.712;
 - (C) Justification that establishing MAOP by another method allowed by this section is impractical;
 - (D) Justification that the reduced MAOP determined by the operator is safe based on analysis of the condition of the pipeline segment, including material properties records, material properties verified in accordance § 192.607, and the history of the pipeline segment, particularly known corrosion and leakage, and the actual operating pressure, and additional compensatory preventive and mitigative measures taken or planned; and
 - (E) Planned duration for operating at the requested MAOP, long-term remediation measures and justification of this operating time interval, including fracture mechanics modeling for failure stress pressures and cyclic fatigue growth analysis and other validated forms of engineering analysis that have been reviewed and confirmed by subject matter experts.
- (3) *Method 3: Engineering Critical Assessment (ECA)*. Conduct an ECA in accordance with § 192.632.
- (4) *Method 4: Pipe Replacement*. Replace the pipeline segment in accordance with this part.
- (5) *Method 5: Pressure Reduction for Pipeline Segments with Small Potential Impact Radius*. Pipelines with a potential impact radius (PIR) less than or equal to 150 feet may establish the MAOP as follows:
 - (i) Reduce the MAOP to no greater than the highest actual operating pressure sustained by the pipeline during 5 years preceding October 1, 2019, divided by 1.1. The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during one continuous 30-day period. The reduced MAOP must account for differences between discharge and upstream pressure on the pipeline by use of either the

lowest value for the entire pipeline segment or the operating pressure gradient (*i.e.*, the location specific operating pressure at each location);

- (ii) Conduct patrols in accordance with § 192.705 paragraphs (a) and (c) and conduct instrumented leakage surveys in accordance with § 192.706 at intervals not to exceed those in the following table 1 to § 192.624(c)(5)(ii):

Table 1 to § 192.624(c)(5)(ii)

Class locations	Patrols	Leakage surveys
(A) Class 1 and Class 2	3 ½ months, but at least four times each calendar year	3 ½ months, but at least four times each calendar year.
(B) Class 3 and Class 4	3 months, but at least six times each calendar year	3 months, but at least six times each calendar year.

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

(6) *Method 6: Alternative Technology.* Operators may use an alternative technical evaluation process that provides a documented engineering analysis for establishing MAOP. If an operator elects to use alternative technology, the operator must notify PHMSA in advance in accordance with § 192.18. The notification must include descriptions of the following details:

- (i) The technology or technologies to be used for tests, examinations, and assessments; the method for establishing material properties; and analytical techniques with similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the pipeline segment being evaluated;
- (ii) Procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects and flaws, and remediate defects discovered;
- (iii) Pipeline segment data, including original design, maintenance and operating history, anomaly or flaw characterization;
- (iv) Assessment techniques and acceptance criteria, including anomaly detection confidence level, probability of detection, and uncertainty of the predicted failure pressure quantified as a fraction of specified minimum yield strength;
- (v) If any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph § 192.712;
- (vi) Operational monitoring procedures;
- (vii) Methodology and criteria used to justify and establish the MAOP; and

- (viii) Documentation of the operator's process and procedures used to implement the use of the alternative technology, including any records generated through its use.
- (d) *Records.* An operator must retain records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this section for the life of the pipeline.

§ 192.625 Odorization of Gas

- (a) A combustible gas in a distribution line must contain a natural odorant or be odorized so that at a concentration in air of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell.
- (b) After December 31, 1976, a combustible gas in a transmission line in a Class 3 or Class 4 location must comply with the requirements of paragraph (a) of this section unless:
 - (1) At least 50 percent of the length of the line downstream from that location is in a Class 1 or Class 2 location;
 - (2) The line transports gas to any of the following facilities which received gas without an odorant from that line before May 5, 1975:
 - (i) An underground storage field;
 - (ii) A gas processing plant;
 - (iii) A gas dehydration plant; or
 - (iv) An industrial plant using gas in a process where the presence of an odorant:
 - (A) Makes the end product unfit for the purpose for which it is intended;
 - (B) Reduces the activity of a catalyst; or
 - (C) Reduces the percentage completion of a chemical reaction;
 - (3) In the case of a lateral line which transports gas to a distribution center, at least 50 percent of the length of that line is in a Class 1 or Class 2 location; or
 - (4) The combustible gas is hydrogen intended for use as a feedstock in a manufacturing process.
- (c) In the concentrations in which it is used, the odorant in combustible gases must comply with the following:
 - (1) The odorant must not be harmful to persons, materials, or pipes.
 - (2) The products of combustion from the odorant may not be toxic when breathed nor may they be corrosive or harmful to those materials to which the products of combustion will be exposed.
- (d) The odorant may not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight.
- (e) Equipment for odorization must introduce the odorant without wide variations in the level of odorant.
- (f) To assure the proper concentration of odorant in accordance with this section, each operator must conduct periodic sampling of combustible gases using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable. Operators of master meter systems may comply with this requirement by:

- (1) Receiving written verification from their gas source that the gas has the proper concentration of odorant, or
 - (2) Conducting periodic “sniff” tests at the extremities of the system to confirm that the gas contains odorant.
- (g) Each operator shall conduct an odorant concentration test by measuring with an instrument designed for this purpose. Systems odorized by centrally located equipment and designed to provide properly odorized gas to a large number of customers, shall have test points at key locations where odorant concentration tests shall be taken. These test points shall be designated in such a manner to allow sampling of gas at the furthest points from the odorizer(s). These tests shall be conducted at intervals not exceeding 3 months and recorded. Records of the current year and the two years immediately preceding the most current year previous test shall be maintained by the operator and provided to the Pipeline Safety Office upon request.
- (h) Individual taps from unodorized facilities shall be provided with odorization equipment of proper size and serviced frequently enough to ensure an ample supply of odorant at all times. Odorant concentration test of this type facility shall be conducted each six months, not to exceed 7 months, with an instruments designed for this purpose. Odorant test records of the current year and the two years immediately preceding the current year o shall be maintained by the operator and provided to the Pipeline Safety Office upon request.

§ 192.627 Tapping Pipelines Under Pressure

Each tap made on a pipeline under pressure must be performed by a crew qualified to make hot taps.

§ 192.629 Purging of Pipelines

- (a) When a pipeline is being purged of air by use of gas, the gas must be released into one end of the line in a moderately rapid and continuous flow. If gas cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the gas.
- (b) When a pipeline is being purged of gas by use of air, the air must be released into one end of the line in a moderately rapid and continuous flow. If air cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the air.
- (c) When a low pressure gas system is being purged of water by natural gas, the allowable operating pressure may not be exceeded. If the pressure required to purge the water exceeds the established maximum allowable operating pressure, air will be used to purge the system.

§ 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;
 - (4) A method of recording controller shift-changes and any hand-over of responsibility between controllers; and
 - (5) The roles, responsibilities and qualifications of others with the authority to direct and supersede the specific technical actions of a controller.
- (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;
- (2) Establish shift lengths and schedule rotations that provide controllers off-duty time sufficient to achieve eight hours of continuous sleep;
 - (3) Educate controllers and supervisors in fatigue mitigation strategies and how off-duty activities contribute to fatigue.
 - (4) Train controllers and supervisors to recognize the effects of fatigue; and
 - (5) 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:
 - (xxv) Controller fatigue;
 - (xxvi) Field equipment;
 - (xxvii) The operation of any relief device;
 - (xxviii) Procedures;
 - (xxix) SCADA system configuration; and
 - (xxx) 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 or 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;
 - (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; and
 - (6) Control room team training and exercises that include both controllers and other individuals, defined by the operator, who would reasonably be expected to operationally collaborate with controllers (control room personnel) during normal, abnormal or emergency situations. Operators must comply with the team training requirements under this paragraph by no later than January 23, 2018.
- (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.

**§ 192.632 Engineering Critical Assessment for Maximum Allowable Operating Pressure
Reconfirmation: Onshore steel transmission pipelines**

When an operator conducts an MAOP reconfirmation in accordance with § 192.624(c)(3) "Method 3" using an ECA to establish the material strength and MAOP of the pipeline segment, the ECA must comply with the requirements of this section. The ECA must assess: Threats; loadings and operational circumstances relevant to those threats, including along the pipeline right-of way; outcomes of the threat assessment; relevant mechanical and fracture properties; in-service degradation or failure processes; and initial and final defect size relevance. The ECA must quantify the interacting effects of threats on any defect in the pipeline.

(a) *ECA Analysis.*

- (1) The material properties required to perform an ECA analysis in accordance with this paragraph are as follows: Diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), and Charpy v-notch toughness values based upon the lowest operational temperatures, if applicable. If any material properties required to perform an ECA for any pipeline segment in accordance with this paragraph are not documented in traceable, verifiable and complete records, an operator must use conservative assumptions and include the pipeline segment in its program to verify the undocumented information in accordance with § 192.607. The ECA must integrate, analyze, and account for the material properties, the results of all tests, direct examinations, destructive tests, and assessments performed in accordance with this section, along with other pertinent information related to pipeline integrity, including close interval surveys, coating surveys, interference surveys required by subpart I of this part, cause analyses of prior incidents, prior pressure test leaks and failures, other leaks, pipe inspections, and prior integrity assessments, including those required by §§ 192.617, 192.710, and subpart O of this part.
- (2) The ECA must analyze and determine the predicted failure pressure for the defect being assessed using procedures that implement the appropriate failure criteria and justification as follows:
 - (i) The ECA must analyze any cracks or crack-like defects remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure of each defect in accordance with § 192.712.
 - (ii) The ECA must analyze any metal loss defects not associated with a dent, including corrosion, gouges, scrapes or other metal loss defects that could remain in the pipe, to determine the predicted failure pressure. ASME/ANSI B31G (incorporated by reference, see § 192.7) or R-STRENG (incorporated by reference, see § 192.7) must be used for corrosion defects. Both procedures and their analysis apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations' procedures. The ECA must use conservative assumptions for metal loss dimensions (length, width, and depth).
 - (iii) When determining the predicted failure pressure for gouges, scrapes, selective seam weld corrosion, crack-related defects, or any defect within a dent, appropriate failure criteria and justification of the criteria must be used and documented.
 - (iv) If SMYS or actual material yield and ultimate tensile strength is not known or not documented by traceable, verifiable, and complete records,

then the operator must assume 30,000 p.s.i. or determine the material properties using § 192.607.

- (3) The ECA must analyze the interaction of defects to conservatively determine the most limiting predicted failure pressure. Examples include, but are not limited to, cracks in or near locations with corrosion metal loss, dents with gouges or other metal loss, or cracks in or near dents or other deformation damage. The ECA must document all evaluations and any assumptions used in the ECA process.
 - (4) The MAOP must be established at the lowest predicted failure pressure for any known or postulated defect, or interacting defects, remaining in the pipe divided by the greater of 1.25 or the applicable factor listed in § 192.619(a)(2)(ii).
- (b) *Assessment to determine defects remaining in the pipe.* An operator must utilize previous pressure tests or develop and implement an assessment program to determine the size of defects remaining in the pipe to be analyzed in accordance with paragraph (a) of this section.
- (1) An operator may use a previous pressure test that complied with subpart J to determine the defects remaining in the pipe if records for a pressure test meeting the requirements of subpart J of this part exist for the pipeline segment. The operator must calculate the largest defect that could have survived the pressure test. The operator must predict how much the defects have grown since the date of the pressure test in accordance with § 192.712. The ECA must analyze the predicted size of the largest defect that could have survived the pressure test that could remain in the pipe at the time the ECA is performed. The operator must calculate the remaining life of the most severe defects that could have survived the pressure test and establish a re-assessment interval in accordance with the methodology in § 192.712.
 - (2) Operators may use an inline inspection program in accordance with paragraph (c) of this section.
 - (3) Operators may use “other technology” if it is validated by a subject matter expert to produce an equivalent understanding of the condition of the pipe equal to or greater than pressure testing or an inline inspection program. If an operator elects to use “other technology” in the ECA, it must notify PHMSA in advance of using the other technology in accordance with § 192.18. The “other technology” notification must have:
 - (i) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments, including characterization of defect size used in the crack assessments (length, depth, and volumetric); and
 - (ii) Procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects, and remediate defects discovered.
- (c) *In-line inspection.* An inline inspection (ILI) program to determine the defects remaining in the pipe for the ECA analysis must be performed using tools that can detect wall loss, deformation from dents, wrinkle bends, ovalities, expansion, seam defects, including cracking and selective seam weld corrosion, longitudinal, circumferential and girth weld cracks, hard spot cracking, and stress corrosion cracking.
- (1) If a pipeline has segments that might be susceptible to hard spots based on assessment, leak, failure, manufacturing vintage history, or other information, then the ILI program must include a tool that can detect hard spots.
 - (2) If the pipeline has had a reportable incident, as defined in § 191.3, attributed to a

girth weld failure since its most recent pressure test, then the ILI program must include a tool that can detect girth weld defects unless the ECA analysis performed in accordance with this section includes an engineering evaluation program to analyze and account for the susceptibility of girth weld failure due to lateral stresses.

- (3) Inline inspection must be performed in accordance with § 192.493.
 - (4) An operator must use unity plots or equivalent methodologies to validate the performance of the ILI tools in identifying and sizing actionable manufacturing and construction related anomalies. Enough data points must be used to validate tool performance at the same or better statistical confidence level provided in the tool specifications. The operator must have a process for identifying defects outside the tool performance specifications and follow up with the ILI vendor to conduct additional in-field examinations, reanalyze ILI data, or both.
 - (5) Interpretation and evaluation of assessment results must meet the requirements of §§ 192.710, 192.713, and subpart O of this part, and must conservatively account for the accuracy and reliability of ILI, in-the-ditch examination methods and tools, and any other assessment and examination results used to determine the actual sizes of cracks, metal loss, deformation and other defect dimensions by applying the most conservative limit of the tool tolerance specification. ILI and in-the-ditch examination tools and procedures for crack assessments (length and depth) must have performance and evaluation standards confirmed for accuracy through confirmation tests for the defect types and pipe material vintage being evaluated. Inaccuracies must be accounted for in the procedures for evaluations and fracture mechanics models for predicted failure pressure determinations.
 - (6) Anomalies detected by ILI assessments must be remediated in accordance with applicable criteria in §§ 192.713 and 192.933.
- (d) *Defect remaining life.* If any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with § 192.712.
 - (e) *Records.* An operator must retain records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this section for the life of the pipeline.

§ 192.634 Transmission lines: Onshore valve shut-off for rupture mitigation.

- (a) *Applicability.* For new or entirely replaced onshore transmission pipeline segments with diameters of 6 inches or greater that are located in high-consequence areas (HCA) or Class 3 or Class 4 locations and that are installed after April 10, 2023, an operator must install or use existing rupture-mitigation valves (RMV), or an alternative equivalent technology, according to the requirements of this section and §§ 192.179 and 192.636. RMVs and alternative equivalent technologies must be operational within 14 days of placing the new or replaced pipeline segment into service. An operator may request an extension of this 14-day operation requirement if it can demonstrate to PHMSA, in accordance with the notification procedures in § 192.18, that application of that requirement would be economically, technically, or operationally infeasible. The requirements of this section apply to all applicable pipe replacement projects, even those

that do not otherwise involve the addition or replacement of a valve. This section does not apply to pipe segments in Class 1 or Class 2 locations that have a potential impact radius (PIR), as defined in § 192.903, that is less than or equal to 150 feet.

(b) *Maximum spacing between valves.* RMVs, or alternative equivalent technology, must be installed in accordance with the following requirements:

(1) *Shut-off segment.* For purposes of this section, a “shut-off segment” means the segment of pipe located between the upstream valve closest to the upstream endpoint of the new or replaced Class 3 or Class 4 or HCA pipeline segment and the downstream valve closest to the downstream endpoint of the new or replaced Class 3 or Class 4 or HCA pipeline segment so that the entirety of the segment that is within the HCA or the Class 3 or Class 4 location is between at least two RMVs or alternative equivalent technologies. If any crossover or lateral pipe for gas receipts or deliveries connects to the shut-off segment between the upstream and downstream valves, the shut-off segment also must extend to a valve on the crossover connection(s) or lateral(s), such that, when all valves are closed, there is no flow path for gas to be transported to the rupture site (except for residual gas already in the shut-off segment). Multiple Class 3 or Class 4 locations or HCA segments may be contained within a single shut-off segment. The operator is not required to select the closest valve to the shut-off segment as the RMV, as that term is defined in § 192.3, or the alternative equivalent technology. An operator may use a manual compressor station valve at a continuously manned station as an alternative equivalent technology, but it must be able to be closed within 30 minutes following rupture identification, as that term is defined at § 192.3. Such a valve used as an alternative equivalent technology would not require a notification to PHMSA in accordance with § 192.18.

(2) *Shut-off segment valve spacing.* A pipeline subject to paragraph (a) of this section must have RMVs or alternative equivalent technology on the upstream and downstream side of the pipeline segment. The distance between RMVs or alternative equivalent technologies must not exceed:

- (i) Eight (8) miles for any Class 4 location,
- (ii) Fifteen (15) miles for any Class 3 location, or
- (iii) Twenty (20) miles for all other locations.

(3) *Laterals.* Laterals extending from shut-off segments that contribute less than 5 percent of the total shut-off segment volume may have RMVs or alternative equivalent technologies that meet the actuation requirements of this section at locations other than mainline receipt/delivery points, as long as all of the laterals contributing gas volumes to the shut-off segment do not contribute more than 5 percent of the total shut-off segment gas volume based upon maximum flow volume at the operating pressure. For laterals that are 12 inches in diameter or less, a check valve that allows gas to flow freely in one direction and contains a mechanism to automatically prevent flow in the other direction may be used as an

alternative equivalent technology where it is positioned to stop flow into the shut-off segment. Such check valves that are used as an alternative equivalent technology in accordance with this paragraph (b)(3) are not subject to § 192.636, but they must be inspected, operated, and remediated in accordance with § 192.745, including for closure and leakage to ensure operational reliability. An operator using such a check valve as an alternative equivalent technology must notify PHMSA in accordance with §§ 192.18 and 192.179 and develop and implement maintenance procedures for such equipment that meet § 192.745.

- (4) *Crossovers.* An operator may use a manual valve as an alternative equivalent technology in lieu of an RMV for a crossover connection if, during normal operations, the valve is closed to prevent the flow of gas by the use of a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator. The operator must develop and implement operating procedures and document that the valve has been closed and locked in accordance with the operator's lock-out and tag-out procedures to prevent the flow of gas. An operator using such a manual valve as an alternative equivalent technology must notify PHMSA in accordance with §§ 192.18 and 192.179.

§ 192.635 Notification of potential rupture.

- (a) As used in this part, a “notification of potential rupture” refers to the notification of, or observation by, an operator (e.g., by or to its controller(s) in a control room, field personnel, nearby pipeline or utility personnel, the public, local responders, or public authorities) of one or more of the below indicia of a potential unintentional or uncontrolled release of a large volume of gas from a pipeline:
 - (1) An unanticipated or unexplained pressure loss outside of the pipeline's normal operating pressures, as defined in the operator's written procedures. The operator must establish in its written procedures that an unanticipated or unplanned pressure loss is outside of the pipeline's normal operating pressures when there is a pressure loss greater than 10 percent occurring within a time interval of 15 minutes or less, unless the operator has documented in its written procedures the operational need for a greater pressure-change threshold due to pipeline flow dynamics (including changes in operating pressure, flow rate, or volume), that are caused by fluctuations in gas demand, gas receipts, or gas deliveries; or
 - (2) An unanticipated or unexplained flow rate change, pressure change, equipment function, or other pipeline instrumentation indication at the upstream or downstream station that may be representative of an event meeting paragraph (a)(1) of this section; or
 - (3) Any unanticipated or unexplained rapid release of a large volume of gas, a fire, or an explosion in the immediate vicinity of the pipeline.
- (b) A notification of potential rupture occurs when an operator first receives notice of or observes an event specified in paragraph (a) of this section.

- (c) This section does not apply to any gas gathering line.

§ 192.636 Transmission lines: Response to a rupture; capabilities of rupture-mitigation valves (RMVs) or alternative equivalent technologies.

- (a) *Scope.* The requirements in this section apply to rupture-mitigation valves (RMVs), as defined in § 192.3, or alternative equivalent technologies, installed pursuant to §§ 192.179(e), (f), and (g) and 192.634.
- (b) *Rupture identification and valve shut-off time.* An operator must, as soon as practicable but within 30 minutes of rupture identification (see § 192.615(a)(12)), fully close any RMVs or alternative equivalent technologies necessary to minimize the volume of gas released from a pipeline and mitigate the consequences of a rupture.
- (c) *Open valves.* An operator may leave an RMV or alternative equivalent technology open for more than 30 minutes, as required by paragraph (b) of this section, if the operator has previously established in its operating procedures and demonstrated within a notice submitted under § 192.18 for PHMSA review, that closing the RMV or alternative equivalent technology would be detrimental to public safety. The request must have been coordinated with appropriate local emergency responders, and the operator and emergency responders must determine that it is safe to leave the valve open. Operators must have written procedures for determining whether to leave an RMV or alternative equivalent technology open, including plans to communicate with local emergency responders and minimize environmental impacts, which must be submitted as part of its notification to PHMSA.
- (d) *Valve monitoring and operation capabilities.* An RMV, as defined in § 192.3, or alternative equivalent technology, must be capable of being monitored or controlled either remotely or by on-site personnel as follows:
 - (1) Operated during normal, abnormal, and emergency operating conditions;
 - (2) Monitored for valve status (i.e., open, closed, or partial closed/open), upstream pressure, and downstream pressure. For automatic shut-off valves (ASV), an operator does not need to monitor remotely a valve's status if the operator has the capability to monitor pressures or gas flow rate within each pipeline segment located between RMVs or alternative equivalent technologies to identify and locate a rupture. Pipeline segments that use manual valves or other alternative equivalent technologies must have the capability to monitor pressures or gas flow rates on the pipeline to identify and locate a rupture; and
 - (3) Have a back-up power source to maintain SCADA systems or other remote communications for remote-control valve (RCV) or automatic shut-off valve (ASV) operational status or be monitored and controlled by on-site personnel.
- (e) *Monitoring of valve shut-off response status.* The position and operational status of an RMV must be appropriately monitored through electronic communication with remote instrumentation or other equivalent means. An operator does not need to monitor remotely

an ASV's status if the operator has the capability to monitor pressures or gas flow rate on the pipeline to identify and locate a rupture.

- (f) *Flow modeling for automatic shut-off valves.* Prior to using an ASV as an RMV, an operator must conduct flow modeling for the shut-off segment and any laterals that feed the shut-off segment, so that the valve will close within 30 minutes or less following rupture identification, consistent with the operator's procedures, and in accordance with § 192.3 and this section. The flow modeling must include the anticipated maximum, normal, or any other flow volumes, pressures, or other operating conditions that may be encountered during the year, not exceeding a period of 15 months, and it must be modeled for the flow between the RMVs or alternative equivalent technologies, and any looped pipelines or gas receipt tie-ins. If operating conditions change that could affect the ASV set pressures and the 30-minute valve closure time after notification of potential rupture, as defined at § 192.3, an operator must conduct a new flow model and reset the ASV set pressures prior to the next review for ASV set pressures in accordance with § 192.745. The flow model must include a time/pressure chart for the segment containing the ASV if a rupture occurs. An operator must conduct this flow modeling prior to making flow condition changes in a manner that could render the 30-minute valve closure time unachievable.
- (g) *Manual valves in non-HCA, Class 1 locations.* For pipeline segments in a Class 1 location that do not meet the definition of a high consequence area (HCA), an operator submitting a notification pursuant to §§ 192.18 and 192.179 for use of manual valves as an alternative equivalent technology may also request an exemption from the requirements of § 192.636(b).
- (h) *Manual operation upon identification of a rupture.* Operators using a manual valve as an alternative equivalent technology as authorized pursuant to §§ 192.18, 192.179, and 192.634 and this section must develop and implement operating procedures that appropriately designate and locate nearby personnel to ensure valve shutoff in accordance with this section and § 192.634. Manual operation of valves must include time for the assembly of necessary operating personnel, the acquisition of necessary tools and equipment, driving time under heavy traffic conditions and at the posted speed limit, walking time to access the valve, and time to shut off all valves manually, not to exceed the maximum response time allowed under paragraph (b) or (c) of this section.

SUBPART M - MAINTENANCE

§ 192.701 Scope

This subpart prescribes minimum requirements for maintenance of pipeline facilities.

§ 192.703 General

- (a) No person may operate a segment of pipeline, unless it is maintained in accordance with this subpart.
- (b) Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service.

- (c) Hazardous leaks must be repaired promptly.

§ 192.705 Transmission Lines: Patrolling

- (a) Each operator shall have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation.
- (b) The frequency of patrols is determined by the size of the line, the operating pressure, the class location, terrain, weather, and other relevant factors, but intervals between patrols may not be longer than prescribed in the following table:

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

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

§ 192.706 Transmission Lines: Leakage Surveys

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

- (a) In Class 3 locations, at intervals not exceeding 7 1/2 months, but at least twice each calendar year; and
- (b) In Class 4 locations, at intervals not exceeding 4 1/2 months, but at least four times each calendar year.

§ 192.707 Line Markers for Mains and Transmission Lines

- (a) *Buried pipelines.* Except as provided in paragraph (b) of this section, a line marker must be placed and maintained as close as practical over each buried main and transmission line:
 - (1) At each crossing of a public road and railroad; and
 - (2) Wherever necessary to identify the location of the transmission line or main to reduce the possibility of damage or interference. When a pipeline crosses a divided roadway, a marker shall be placed on each side of the roadway.
- (b) *Exceptions for buried pipelines.* Line markers are not required for the following pipelines:
 - (1) Mains and transmission lines located at crossings of or under waterways and other bodies of water.

- (2) Mains in Class 3 or Class 4 locations where a damage prevention program is in effect under

§ 192.614:

- (3) Transmission lines in Class 3 or 4 locations where placement of a line marker is impractical.
- (c) *Pipelines above ground.* Line markers must be placed and maintained along each section of a main and transmission line that is located above-ground in an area accessible to the public.
- (d) *Marker warning.* The following must be written legibly on a background of sharply contrasting color on each line marker:
- (1) The word "Warning", "Caution", or "Danger", followed by the words "Gas Pipeline" all of which, except for markers in heavily developed urban areas, must be in letters at least one inch (25 millimeters) high with one-quarter inch (6.4 millimeters) stroke.
 - (2) The name of the operator and the telephone number (including area code) where the operator can be reached at all times.

§ 192.709 Transmission Lines: Record-Keeping

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

- (a) The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipe remains in service.
- (b) The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 5 years. However, repairs generated by patrols, surveys, inspections, or tests required by subparts L and M of this part must be retained in accordance with paragraph (c) of this section.
- (c) A record of each patrol, survey, inspection, and test required by subparts L and M of this part must be retained for at least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.

§ 192.710 Transmission lines: Assessments outside of high consequence areas

- (a) *Applicability:* This section applies to onshore steel transmission pipeline segments with a maximum allowable operating pressure of greater than or equal to 30% of the specified minimum yield strength and are located in:
 - (1) A Class 3 or Class 4 location; or
 - (2) A moderate consequence area as defined in § 192.3, if the pipeline segment can accommodate inspection by means of an instrumented inline inspection tool (i.e., "smart pig").
 - (3) This section does not apply to a pipeline segment located in a high consequence area as defined in § 192.903.
- (b) *General -*
 - (1) *Initial assessment.* An operator must perform initial assessments in accordance with this section based on a risk-based prioritization schedule and complete initial assessment for all applicable pipeline segments no later than July 3, 2034, or as soon as practicable but not to exceed 10 years after the pipeline segment first

meets the conditions of § 192.710(a) (e.g., due to a change in class location or the area becomes a moderate consequence area), whichever is later.

- (2) *Periodic reassessment.* An operator must perform periodic reassessments at least once every 10 years, with intervals not to exceed 126 months, or a shorter reassessment interval based upon the type of anomaly, operational, material, and environmental conditions found on the pipeline segment, or as necessary to ensure public safety.
 - (3) *Prior assessment.* An operator may use a prior assessment conducted before July 1, 2020 as an initial assessment for the pipeline segment, if the assessment met the subpart O requirements of part 192 for in-line inspection at the time of the assessment. If an operator uses this prior assessment as its initial assessment, the operator must reassess the pipeline segment according to the reassessment interval specified in paragraph (b)(2) of this section calculated from the date of the prior assessment.
 - (4) *MAOP verification.* An integrity assessment conducted in accordance with the requirements of § 192.624(c) for establishing MAOP may be used as an initial assessment or reassessment under this section.
- (c) *Assessment method.* The initial assessments and the reassessments required by paragraph (b) of this section must be capable of identifying anomalies and defects associated with each of the threats to which the pipeline segment is susceptible and must be performed using one or more of the following methods:
- (1) *Internal inspection.* Internal inspection tool or tools capable of detecting those threats to which the pipeline is susceptible, such as corrosion, deformation and mechanical damage (e.g., dents, gouges and grooves), material cracking and crack-like defects (e.g., stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493;
 - (2) *Pressure test.* Pressure test conducted in accordance with subpart J of this part. The use of subpart J pressure testing is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms; manufacturing and related defect threats, including defective pipe and pipe seams; and stress corrosion cracking, selective seam weld corrosion, dents and other forms of mechanical damage;
 - (3) *Spike hydrostatic pressure test.* A spike hydrostatic pressure test conducted in accordance with § 192.506. A spike hydrostatic pressure test is appropriate for time-dependent threats such as stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects;
 - (4) *Direct examination.* Excavation and in situ direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all applicable threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), Inverse Wave Field Extrapolation (IWEX), radiography, and magnetic particle inspection (MPI);

- (5) *Guided Wave Ultrasonic Testing.* Guided Wave Ultrasonic Testing (GWUT) as described in Appendix F;
 - (6) *Direct assessment.* Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in §§ 192.925, 192.927 and 192.929; or
 - (7) *Other technology.* Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify PHMSA in advance of using the other technology in accordance with § 192.18.
- (d) *Data analysis.* An operator must analyze and account for the data obtained from an assessment performed under paragraph (c) of this section to determine if a condition could adversely affect the safe operation of the pipeline using personnel qualified by knowledge, training, and experience. In addition, when analyzing inline inspection data, an operator must account for uncertainties in reported results (e.g., tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies.
 - (e) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that 180 days is impracticable.
 - (f) *Remediation.* An operator must comply with the requirements in §§ 192.485, 192.711, 192.712, 192.713, and 192.714 where applicable, if a condition that could adversely affect the safe operation of a pipeline is discovered.
 - (g) *Analysis of information.* An operator must analyze and account for all available relevant information about a pipeline in complying with the requirements in paragraphs (a) through (f) of this section.

§ 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)
 - (i) Non-integrity management repairs for gathering lines and offshore

transmission lines: For gathering lines subject to this section in accordance with § 192.9 and for offshore transmission lines, an operator must make permanent repairs as soon as feasible.

(ii) Non-integrity management repairs for onshore transmission lines: Except for gathering lines exempted from this section in accordance with § 192.9 and offshore transmission lines, after May 24, 2023, whenever an operator discovers any condition that could adversely affect the safe operation of a pipeline segment not covered by an integrity management program under subpart O of this part, it must correct the condition as prescribed in § 192.714.

(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.

§ 192.712 Analysis of predicted failure pressure

(a) *Applicability.* Whenever required by this part, operators of onshore steel transmission pipelines must analyze anomalies or defects to determine the predicted failure pressure at the location of the anomaly or defect, and the remaining life of the pipeline segment at the location of the anomaly or defect, in accordance with this section.

(b) *Corrosion metal loss.* When analyzing corrosion metal loss under this section, an operator must use a suitable remaining strength calculation method including, ASME/ANSI B31G (incorporated by reference, see § 192.7); R-STRENG (incorporated by reference, see § 192.7); or an alternative equivalent method of remaining strength calculation that will provide an equally conservative result.

(1) If an operator would choose to use a remaining strength calculation method that could provide a less conservative result than the methods listed in paragraph (b) introductory text, the operator must notify PHMSA in advance in accordance with § 192.18(c).

(2) The notification provided for by paragraph (b)(1) of this section must include a comparison of its predicted failure pressures to R-STRENG or ASME/ANSI B31G, all burst pressure tests used, and any other technical reviews used to qualify the calculation method(s) for varying corrosion profiles.

(c) Dents and other mechanical damage. To evaluate dents and other mechanical damage that could result in a stress riser or other integrity impact, an operator must develop a procedure and perform an engineering critical assessment as follows:

(1) Identify and evaluate potential threats to the pipe segment in the vicinity of the anomaly or defect, including ground movement, external loading, fatigue, cracking, and corrosion.

(2) Review high-resolution magnetic flux leakage (HR-MFL) high-resolution deformation, inertial mapping, and crack detection inline inspection data for damage in the dent area and any associated weld region, including available data from previous inline inspections.

(3) Perform pipeline curvature-based strain analysis using recent HR-Deformation inspection data.

- (4) Compare the dent profile between the most recent and previous in-line inspections to identify significant changes in dent depth and shape.
 - (5) Identify and quantify all previous and present significant loads acting on the dent.
 - (6) Evaluate the strain level associated with the anomaly or defect and any nearby welds using Finite Element Analysis, or other technology in accordance with this section. Using Finite Element Analysis to quantify the dent strain, and then estimating and evaluating the damage using the Strain Limit Damage (SLD) and Ductile Failure Damage Indicator (DFDI) at the dent, are appropriate evaluation methods.
 - (7) The analyses performed in accordance with this section must account for material property uncertainties, model inaccuracies, and inline inspection tool sizing tolerances.
 - (8) Dents with a depth greater than 10 percent of the pipe outside diameter or with geometric strain levels that exceed the lesser of 10 percent or exceed the critical strain for the pipe material properties must be remediated in accordance with § 192.713, § 192.714, or § 192.933, as applicable.
 - (9) Using operational pressure data, a valid fatigue life prediction model that is appropriate for the pipeline segment, and assuming a reassessment safety factor of 5 or greater for the assessment interval, estimate the fatigue life of the dent by Finite Element Analysis or other analytical technique that is technically appropriate for dent assessment and reassessment intervals in accordance with this section. Multiple dent or other fatigue models must be used for the evaluation as a part of the engineering critical assessment.
 - (10) If the dent or mechanical damage is suspected to have cracks, then a crack growth rate assessment is required to ensure adequate life for the dent with crack(s) until remediation or the dent with crack(s) must be evaluated and remediated in accordance with the criteria and timing requirements in § 192.713, § 192.714, or § 192.933, as applicable.
 - (11) An operator using an engineering critical assessment procedure, other technologies, or techniques to comply with paragraph (c) of this section must submit advance notification to PHMSA, with the relevant procedures, in accordance with § 192.18.
- (d) *Cracks and crack-like defects -*
- (1) *Crack analysis models.* When analyzing cracks and crack-like defects under this section, an operator must determine predicted failure pressure, failure stress pressure, and crack growth using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both), material properties (pipe and weld properties), and boundary condition used (pressure test, ILI, or other).
 - (2) *Analysis for crack growth and remaining life.* If the pipeline segment is susceptible to cyclic fatigue or other loading conditions that could lead to fatigue crack growth, fatigue analysis must be performed using an applicable fatigue crack growth law (for example, Paris Law) or other technically appropriate engineering methodology. For other degradation processes that can cause crack growth, appropriate engineering analysis must be used. The above methodologies must be validated by a subject matter expert to determine conservative predictions of flaw growth and remaining life at the maximum allowable operating pressure. The operator must calculate the remaining life of the pipeline by determining the

amount of time required for the crack to grow to a size that would fail at maximum allowable operating pressure.

- (i) When calculating crack size that would fail at MAOP, and the material toughness is not documented in traceable, verifiable, and complete records, the same Charpy v-notch toughness value established in paragraph (e)(2) of this section must be used.
 - (ii) Initial and final flaw size must be determined using a fracture mechanics model appropriate to the failure mode (ductile, brittle or both) and boundary condition used (pressure test, ILI, or other).
 - (iii) An operator must re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated by this analysis has expired. The operator must determine and document if further pressure tests or use of other assessment methods are required at that time. The operator must continue to re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated in the most recent evaluation has expired.
- (3) *Cracks that survive pressure testing.* For cases in which the operator does not have in-line inspection crack anomaly data and is analyzing potential crack defects that could have survived a pressure test, the operator must calculate the largest potential crack defect sizes using the methods in paragraph (d)(1) of this section. If pipe material toughness is not documented in traceable, verifiable, and complete records, the operator must use one of the following for Charpy v-notch toughness values based upon minimum operational temperature and equivalent to a full-size specimen value:
- (i) Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;
 - (ii) A conservative Charpy v-notch toughness value to determine the toughness based upon the material properties verification process specified in § 192.607;
 - (iii) A full size equivalent Charpy v-notch upper-shelf toughness level of 120 ft.-lbs.; or
 - (iv) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of the crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in accordance with § 192.18.
- (e) *Data.* In performing the analyses of predicted or assumed anomalies or defects in accordance with this section, an operator must use data as follows.
- (1) An operator must explicitly analyze and account for uncertainties in reported assessment results (including tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance) in identifying and characterizing the type and dimensions of anomalies or defects used in the analyses, unless the defect dimensions have been verified using *in situ* direct measurements.
 - (2) The analyses performed in accordance with this section must utilize pipe and material properties that are documented in traceable, verifiable, and complete

records. If documented data required for any analysis is not available, an operator must obtain the undocumented data through § 192.607. Until documented material properties are available, the operator shall use conservative assumptions as follows:

- (i) *Material toughness.* An operator must use one of the following for material toughness:
 - (A) Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;
 - (B) A conservative Charpy v-notch toughness value to determine the toughness based upon the ongoing material properties verification process specified in § 192.607;
 - (C) If the pipeline segment does not have a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 13.0 ft.- lbs. for body cracks and 4.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion defects;
 - (D) If the pipeline segment has a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 5.0 ft.-lbs. for body cracks and 1.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion; or
 - (E) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in advance in accordance with § 192.18 and include in the notification the bases for demonstrating that the Charpy v-notch toughness values proposed are appropriate and conservative for use in analysis of crack-related conditions.
 - (ii) *Material strength.* An operator must assume one of the following for material strength:
 - (A) Grade A pipe (30,000 psi), or
 - (B) The specified minimum yield strength that is the basis for the current maximum allowable operating pressure.
 - (iii) *Pipe dimensions and other data.* Until pipe wall thickness, diameter, or other data are determined and documented in accordance with § 192.607, the operator must use values upon which the current MAOP is based.
- (f) *Review.* Analyses conducted in accordance with this section must be reviewed and confirmed by a subject matter expert.
 - (g) *Records.* An operator must keep for the life of the pipeline records of the investigations, analyses, and other actions taken in accordance with the requirements of this section. Records must document justifications, deviations, and determinations made for the following, as applicable:
 - (1) The technical approach used for the analysis;
 - (2) All data used and analyzed;

- (3) Pipe and weld properties;
 - (4) Procedures used;
 - (5) Evaluation methodology used;
 - (6) Models used;
 - (7) Direct in situ examination data;
 - (8) In-line inspection tool run information evaluated, including any multiple in-line inspection tool runs;
 - (9) Pressure test data and results;
 - (10) In-the-ditch assessments;
 - (11) All measurement tool, assessment, and evaluation accuracy specifications and tolerances used in technical and operational results;
 - (12) All finite element analysis results;
 - (13) The number of pressure cycles to failure, the equivalent number of annual pressure cycles, and the pressure cycle counting method;
 - (14) The predicted fatigue life and predicted failure pressure from the required fatigue life models and fracture mechanics evaluation methods;
 - (15) Safety factors used for fatigue life and/or predicted failure pressure calculations;
 - (16) Reassessment time interval and safety factors;
 - (17) The date of the review;
 - (18) Confirmation of the results by qualified technical subject matter experts; and
 - (19) Approval by responsible operator management personnel.
- (h) *Reassessments*. If an operator uses an engineering critical assessment method in accordance with paragraphs (c) and (d) of this section to determine the maximum reevaluation intervals, the operator must reassess the anomalies as follows:
- (1) If the anomaly is in an HCA, the operator must reassess the anomaly within a maximum of 7 years in accordance with § 192.939(a), unless the safety factor is expected to go below what is specified in paragraph (c) or (d) of this section.
 - (2) If the anomaly is outside of an HCA, the operator must perform a reassessment of the anomaly within a maximum of 10 years in accordance with § 192.710(b), unless the anomaly safety factor is expected to go below what is specified in paragraph (c) or (d) of this section.

§ 192.713 Transmission Lines: Permanent Field Repair of Imperfections and Damages

- (a) Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be--
 - (1) Removed by cutting out and replacing a cylindrical piece of pipe; or
 - (2) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.
- (b) Operating pressure must be at a safe level during repair operations.

§ 192.714 Transmission lines: Repair criteria for onshore transmission pipelines.

- (a) *Applicability.* This section applies to onshore transmission pipelines not subject to the repair criteria in subpart O of this part, and which do not operate under an alternative MAOP in accordance with §§ 192.112, 192.328, and 192.620. Pipeline segments that are located in high consequence areas, as defined in § 192.903, must comply with the applicable actions specified by the integrity management requirements in subpart O. Pipeline segments operating under an alternative MAOP in accordance with §§ 192.112, 192.328, and 192.620 must comply with § 192.620(d)(11).
- (b) *General.* Each operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe manner and are made to prevent damage to persons, property, and the environment. A pipeline segment's operating pressure must be less than the predicted failure pressure determined in accordance with § 192.712 during repair operations. Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis, including predicted failure pressure for determining MAOP, is not available, an operator must obtain the undocumented data through § 192.607. Until documented material properties are available, the operator must use the conservative assumptions in either § 192.712(e)(2) or, if appropriate following a pressure test, in § 192.712(d)(3).
- (c) *Schedule for evaluation and remediation.* An operator must remediate conditions according to a schedule that prioritizes the conditions for evaluation and remediation. Unless paragraph (d) of this section provides a special requirement for remediating certain conditions, an operator must calculate the predicted failure pressure of anomalies or defects and follow the schedule in ASME B31.8S (incorporated by reference, see § 192.7). If an operator cannot meet the schedule for any condition, the operator must document the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety. Each condition that meets any of the repair criteria in paragraph (d) of this section in an onshore steel transmission pipeline must be—
 - (1) Removed by cutting out and replacing a cylindrical piece of pipe that will permanently restore the pipeline's MAOP based on the use of § 192.105 and the design factors for the class location in which it is located; or
 - (2) Repaired by a method, shown by technically proven engineering tests and analyses, that will permanently restore the pipeline's MAOP based upon the determined predicted failure pressure times the design factor for the class location in which it is located.
- (d) *Remediation of certain conditions.* For onshore transmission pipelines not located in high consequence areas, an operator must remediate a listed condition according to the following criteria:
 - (1) *Immediate repair conditions.* An operator's evaluation and remediation schedule for immediate repair conditions must follow section 7 of ASME/ANSI B31.8S-2004 (incorporated by reference, see § 192.7). An operator must repair the following conditions immediately upon discovery:
 - (i) Metal loss anomalies where a calculation of the remaining strength of the pipe at the location of the anomaly shows a predicted failure pressure,

determined in accordance with § 192.712(b), of less than or equal to 1.1 times the MAOP.

- (ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.
 - (iii) Metal loss greater than 80 percent of nominal wall regardless of dimensions.
 - (iv) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or has a longitudinal joint factor less than 1.0, and the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.25 times the MAOP.
 - (v) A crack or crack-like anomaly meeting any of the following criteria:
 - (A) Crack depth plus any metal loss is greater than 50 percent of pipe wall thickness;
 - (B) Crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth; or
 - (C) The crack or crack-like anomaly has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.25 times the MAOP.
 - (vi) An indication or anomaly that, in the judgment of the person designated by the operator to evaluate the assessment results, requires immediate action.
- (2) *Two-year conditions.* An operator must repair the following conditions within 2 years of discovery:
- (i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.
 - (ii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld, unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.
 - (iii) A dent located between the 4 o'clock and 8 o'clock positions (lower 1/3 of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.
 - (iv) For metal loss anomalies, a calculation of the remaining strength of the pipe shows a predicted failure pressure, determined in accordance with §

192.712(b) at the location of the anomaly, of less than 1.39 times the MAOP for Class 2 locations, or less than 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME/ANSI B31.8S-2004 (incorporated by reference, see § 192.7), section 7, Figure 4, as specified in paragraph (c) of this section.

- (v) Metal loss that is located at a crossing of another pipeline, is in an area with widespread circumferential corrosion, or could affect a girth weld, and that has a predicted failure pressure, determined in accordance with § 192.712(b), less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.
 - (vi) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0, and where the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.
 - (vii) A crack or crack-like anomaly that has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.
- (3) *Monitored conditions.* An operator must record and monitor the following conditions during subsequent risk assessments and integrity assessments for any change that may require remediation.
- (i) A dent that is located between the 4 o'clock and 8 o'clock positions (bottom 1/3 of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and where an engineering analysis, performed in accordance with § 192.712(c), demonstrates critical strain levels are not exceeded.
 - (ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and where an engineering analysis performed in accordance with § 192.712(c) determines that critical strain levels are not exceeded.
 - (iii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal or helical (spiral) seam weld, and where an engineering analysis of the dent and girth or seam weld, performed in accordance with § 192.712(c), demonstrates critical strain levels are not exceeded. These analyses must consider weld mechanical properties.

- (iv) A dent that has metal loss, cracking, or a stress riser, and where an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.
 - (v) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or is greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.
 - (vi) A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or is greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.
- (e) Temporary pressure reduction.
- (1) Immediately upon discovery and until an operator remediates the condition specified in paragraph (d)(1) of this section, or upon a determination by an operator that it is unable to respond within the time limits for the conditions specified in paragraph (d)(2) of this section, the operator must reduce the operating pressure of the affected pipeline to any one of the following based on safety considerations for the public and operating personnel:
 - (i) A level not exceeding 80 percent of the operating pressure at the time the condition was discovered;
 - (ii) A level not exceeding the predicted failure pressure times the design factor for the class location in which the affected pipeline is located; or
 - (iii) A level not exceeding the predicted failure pressure divided by 1.1.
 - (2) An operator must notify PHMSA in accordance with § 192.18 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) or (d) of this section and cannot provide safety through a temporary reduction in operating pressure or other action. Notification to PHMSA does not alleviate an operator from the evaluation, remediation, or pressure reduction requirements in this section.
 - (3) When a pressure reduction, in accordance with paragraph (e) of this section, exceeds 365 days, an operator must notify PHMSA in accordance with § 192.18 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline.
 - (4) An operator must document and keep records of the calculations and decisions used to determine the reduced operating pressure and the implementation of the actual reduced operating pressure for a period of 5 years after the pipeline has been repaired.

- (f) *Other conditions.* Unless another timeframe is specified in paragraph (d) of this section, an operator must take appropriate remedial action to correct any condition that could adversely affect the safe operation of a pipeline system in accordance with the criteria, schedules, and methods defined in the operator's operating and maintenance procedures.
- (g) *In situ direct examination of crack defects.* Whenever an operator finds conditions that require the pipeline to be repaired, in accordance with this section, an operator must perform a direct examination of known locations of cracks or crack-like defects using technology that has been validated to detect tight cracks (equal to or less than 0.008 inches crack opening), such as inverse wave field extrapolation (IWEX), phased array ultrasonic testing (PAUT), ultrasonic testing (UT), or equivalent technology. "In situ" examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection for accuracy of the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations.
- (h) *Determining predicted failure pressures and critical strain levels.* An operator must perform all determinations of predicted failure pressures and critical strain levels required by this section in accordance with § 192.712.

§ 192.715 Transmission Lines: Permanent Field Repair of Welds

Each weld that is unacceptable under § 192.241(c) must be repaired as follows:

- (a) If it is feasible to take the segment of transmission line out of service, the weld must be repaired in accordance with the applicable requirements of § 192.245.
- (b) A weld may be repaired in accordance with § 192.245 while the segment of transmission line is in service if:
 - (1) The weld is not leaking;
 - (2) The pressure in the segment is reduced so that it does not produce a stress that is more than 20 percent of the SMYS of the pipe; and
 - (3) Grinding of the defective area can be limited so that at least 1/8 inch (3.2 millimeters) thickness in the pipe weld remains.
- (c) A defective weld which cannot be repaired in accordance with paragraph (a) or (b) of this section must be repaired by installing a full encirclement welded split sleeve of appropriate design.

§ 192.717 Transmission Lines: Permanent Field Repair of Leaks

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

- (a) Removing the leak by cutting out and replacing a cylindrical piece of pipe; or
- (b) Repairing the leak by one of the following methods:
 - (1) Install a full encirclement welded split sleeve of appropriate design, unless the transmission line is joined by mechanical couplings and operates at less than 40 percent of SMYS.
 - (2) If the leak is due to a corrosion pit, install a properly designed bolt-on-leak clamp.

- (3) If the leak is due to a corrosion pit and on pipe of not more than 40,000 p.s.i. (267 MPa) SMYS, fillet weld over the pitted area a steel plate patch with rounded corners, of the same or greater thickness than the pipe, and not more than one-half of the diameter of the pipe in size.
- (4) If the leak is on a submerged offshore pipeline or submerged pipeline in inland navigable waters, mechanically apply a full encirclement split sleeve of appropriate design.
- (5) Apply a method that reliable engineering tests and analyses show can permanently

§ 192.719 Transmission Lines: Testing of Repairs

- (a) Testing of replacement pipe. If a segment of transmission line is repaired by cutting out the damaged portion of the pipe as a cylinder, the replacement pipe must be tested to the pressure required for a new line installed in the same location. This test may be made on the pipe before it is installed.
- (b) Testing of repairs made by welding. Each repair made by welding in accordance with §§ 192.713, 192.715, and 192.717 must be examined in accordance with § 192.241.

§192.720 Distribution Systems: Leak Repair

Mechanical leak repair clamps installed after January 22, 2019 may not be used as a permanent repair method for plastic pipe.

§ 192.721 Distribution Systems: Patrolling

- (a) The frequency of patrolling mains must be determined by the severity of the conditions which could cause failure or leakage, and the consequent hazards to public safety.
- (b) Mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage must be patrolled -
 - (1) In business districts, at intervals not exceeding 4 1/2 months, but at least 4 times each calendar year; and
 - (2) Outside business districts, at intervals not exceeding 7 1/2 months, but at least twice each calendar year

§ 192.723 Distribution Systems: Leakage Surveys and Procedures

- (a) Each operator of a distribution system shall conduct periodic leakage surveys in accordance with this section. These surveys must be performed by, or under the direct supervision of, personnel trained and qualified in both the use of appropriate equipment and the classification of leaks. In addition, maps that approximate the location of the mains and transmission lines being surveyed must be available.
- (b) The type and scope of the leakage control program must be determined by the nature of the operations and the local conditions, but it must meet the following minimum requirements.
 - (1) A leakage survey with leak detector equipment shall be conducted in business districts including test of the atmosphere in electric, gas, sewer, telephone, and water system manholes, at cracks in pavement and sidewalks and at other locations providing an opportunity for finding gas leaks. This survey shall be performed with a flame ionization unit or a gas detector at intervals not exceeding 15 months, but at least once each calendar year.

- (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.
 - (i) A leakage survey of all underground natural gas distribution systems outside of a business district, that are owned/operated or the responsibility of a public or municipal utility shall be performed as frequently as necessary but at intervals not exceeding five (5) calendar years.
 - (ii) A leakage survey of all underground natural gas distribution systems, not owned nor the responsibility of a public or municipal utility and used to transport gas from a master meter or utility company gas main to multiple buildings, shall be performed as frequently as necessary but at intervals not exceeding five (5) years. Owners/operators of these systems shall be responsible to ensure these surveys are accomplished.
- (c) The type and scope of the surveys required in subdivisions (b)(2)(i) and (ii) of this section, must ensure detection, location, evaluation and classification of any gas leakage. The following methods may be employed depending on the design and size of the system or facility:
 - (1) Flame Ionization Detector.
 - (2) Combustible Gas Indicator (includes bar holing).
 - (3) Pressure Drop or No Flow. Only to be used to establish the presence or absence of leakage on a distribution system. Where leakage is indicated, further evaluation by another detection method must be accomplished to locate, evaluate and classify leaks. When this method is used to verify no leakage exists a test record certified by a qualified person, organization or agency must be retained with records of survey.

NOTE: *Test duration must be of sufficient length to detect leakage, and the following should be considered:*

Volume under test and the time for the test medium to become temperature stabilized.

- (d) All leaks detected shall be classified to assure a standardized priority of repair is established. There is no precise means presently developed to accurately classify leaks, however, there are four general categories that must be considered when judging the severity of gas leaks:
 - (1) Proportion. The quantity of gas escaping based on gas indicator readings, pressure of line or container from which gas is escaping and concentration of odor.
 - (2) Location. The centralized location of escaping gas; under buildings and paved surfaces, near occupied buildings, near source of ignition or in open areas where the concentration of gas is improbable.
 - (3) Dispersion. The areas to which escaping gas may spread. Based on depth of line, type of soil, pressure, surface cover, moisture, frozen soil and other soil conditions.
 - (4) Evaluation. All factors must be evaluated, applying experience and good judgment in arriving at the proper classification.

- (e) To standardize leak classification, using the above factors, all leaks shall be classified in the following categories:
 - (1) Class 1. Leaks that represent an existing or probable hazard to persons or property and requires immediate repair or continuous action until the hazardous condition no longer exists.
 - (2) Class 2. Leaks that are considered non-hazardous at the time of detection, but could become hazardous if repair is not accomplished in a reasonable length of time. Repair as soon as possible, but within a period not to exceed five months.
 - (3) Class 3. Leaks that are non-hazardous at the time of detection and can be expected to remain non-hazardous. These leaks should be re-evaluated during the next scheduled survey. Repair as time and expenditures permit.
- (f)
 - (1) In addition to leak surveys, any leak or gas odor reported from the public, fire, police or other authorities or notification of damage to facilities by outside sources shall require prompt investigation. Thorough investigations shall be performed on all suspected leaks to determine the degree of existing hazard to person or property. This includes entering structures in a reported or suspected leakage area and checking for presence of gas.
 - (2) Leaks reported on customer's piping shall be investigated by trained and qualified employees who must judge the degree of hazard and establish the required repair priority. If a hazardous leak exists on customer's piping, the service shall be immediately terminated upstream of the leak. If the leak is not presently hazardous but may become hazardous, the customer shall be given a reasonable time to repair the leak.
- (g) A leak repair record shall be made for every leak detected or identified. Leaks discovered on customer's piping, downstream of the meter, shall be documented on operator's service orders and retained until the customer's piping has been repaired to the satisfaction of the operator. Corrosion leaks shall be documented on permanent records and shall be retained for as long as the segment of pipeline on which the leak was located is in service. As a minimum, leak records other than corrosion shall be maintained on the two most current leak surveys. Each leak record shall contain, as a minimum, the following:
 - (1) Date leak discovered.
 - (2) Location.
 - (3) Classification.
 - (4) Cause of leak.
 - (5) Unique identifier for person making the repair or responsible for maintaining the records of work accomplished.
- (h) Leaks may be reclassified by responsible and suitable experienced persons whose name shall appear on the documents.

§ 192.724 Hazardous Facilities

- (a) If at any time the supplier to a master meter system or private line system becomes aware that the receiving system is experiencing a lost and unaccounted for gas percentage of ten percent (10%) or more, as calculated on a rolling average over the prior year, the supplier may terminate service to the receiving system without delay.

- (b) If at any time the supplier to a master meter system or private line system becomes aware that the receiving system has an operating condition which causes it to deliver gas service in an unsafe manner and endanger life or property, the supplier shall terminate service to the receiving system without delay.
- (c) Following the termination of service pursuant to (a) or (b) above, the supplier to a master meter system or private line system shall make contact with PSO personnel by telephone or electronic mail within one hour of termination and provide a detailed justification for such termination.
- (d) Prior to reconnection of service to a master meter system or private line system that has been terminated pursuant to (a) or (b) above, the supplier shall comply with its reconnection policy.

§ 192.725 Test Requirements for Reinstating Service Lines

- (a) Except as provided in paragraph (b) of this section, each disconnected service line must be tested in the same manner as a new service line, before being reinstated.
- (b) Each service line temporarily disconnected from the main must be tested from the point of disconnection to the service line valve in the same manner as a new service line, before reconnecting. However, if provisions are made to maintain continuous service, such as installation of a bypass, any part of the original service line used to maintain continuous service need not be tested.

§ 192.727 Abandonment or Deactivation of Facilities

- (a) Each operator shall conduct abandonment or deactivation of pipelines in accordance with the requirements of this section.
- (b) Each pipeline abandoned in place must be disconnected from all sources and supplies of gas, purged of gas, and the ends sealed. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.
- (c) Except for service lines, each inactive pipeline that is not being maintained under this part must be disconnected from all sources and supplies of gas, purged of gas, and the ends sealed. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.
- (d) Whenever service to a customer is discontinued, one of the following must be complied with:
 - (1) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.
 - (2) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.
 - (3) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.
- (e) If air is used for purging, the operator shall ensure that a combustible mixture is not present after purging.
- (f) Each abandoned vault must be filled with a suitable compacted material.
- (g) For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility

- (1) The preferred method to submit data on pipeline facilities abandoned after October 10, 2000, is to the National Pipeline Mapping System (NPMS) in accordance with the NPMS "Standards for Pipeline and Liquefied Natural Gas Operator Submissions." To obtain a copy of the NPMS Standards, please refer to the NPMS homepage at www.npms.phmsa.dot.gov. A digital data format is preferred, but hard copy submissions are acceptable if they comply with the NPMS Standards. In addition to the NPMS-required attributes, operators must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the operator's knowledge, all of the reasonably available information requested was provided and, to the best of the operator's knowledge, the abandonment was completed in accordance with applicable laws. Refer to the NPMS Standards for details in preparing your data for submission. The NPMS Standards also include details of how to submit data. Alternatively, operators may submit reports by mail, fax or email to the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP-10, 1200 New Jersey Avenue SE, Washington, DC 20590-0001; fax (202) 366-4566; email InformationResourcesManager@dot.gov. The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws.
- (2) [Reserved].

§ 192.731 Compressor Stations: Inspection and Testing of Relief Devices

- (a) Except for rupture discs, each pressure relieving device in a compressor station must be inspected and tested in accordance with §§ 192.739 and 192.743, and must be operated periodically to determine that it opens at the correct set pressure.
- (b) Any defective or inadequate equipment found must be promptly repaired or replaced.
- (c) Each remote control shutdown device must be inspected and tested, at intervals not exceeding 15 months, but at least once each calendar year, to determine that it functions properly.

§ 192.735 Compressor Stations: Storage of Combustible Materials

- (a) Flammable or combustible materials in quantities beyond those required for everyday use, or other than those normally used in compressor buildings, must be stored a safe distance from the compressor building.
- (b) Above-ground oil or gasoline storage tanks must be protected in accordance with NFPA-30 (incorporated by reference, see § 192.7).

§ 192.736 Compressor Stations: Gas Detection

- (a) Not later than September 16, 1996, each compressor building in a compressor station must have a fixed gas detection and alarm system, unless the building is:
 - (1) Constructed so that at least 50 percent of its upright side area is permanently open; or
 - (2) Located in an unattended field compressor station of 1,000 horsepower (746 kW) or less.
- (b) Except when shutdown of the system is necessary for maintenance under paragraph (c) of this section, each gas detection and alarm system required by this section must:

- (1) Continuously monitor the compressor building for a concentration of gas in air of not more than 25 percent of the lower explosive limit; and
 - (2) If that concentration of gas is detected, warn persons about to enter the building and persons inside the building of the danger.
- (c) Each gas detection and alarm system required by this section must be maintained to function properly. The maintenance must include performance tests.

§ 192.739 Pressure Limiting and Regulating Stations: Inspection and Testing

- (a) Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected, at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests. These inspections and tests shall include the following:
- (1) Pressure regulating devices.
 - (i) Each regulator must be inspected to ensure it is in good working order, controls pressure and capacity within acceptable limits for the system in which it is installed.
 - (ii) Shuts off pressure within acceptable limits.
 - (iii) Second stage regulator will withstand and control first stage inlet pressure if a relief valve is not installed between regulators.
 - (iv) Properly installed control lines, controllers, actuators and protected from conditions that may prevent proper operation.
 - (v) Except as provided in paragraph (b) of this section, set to control or relieve at the correct pressure consistent with the pressure limits of § 192.201(a); and
 - (2) Pressure limiting and relief devices.
 - (i) Monitor regulators tested for proper operating parameters.
 - (ii) Except as provided in paragraph (b) of this section set to control or relieve at the correct pressure consistent with the pressure limits of § 192.201 (a); and
 - (iii) Vent stacks are free of obstructions, properly routed, vented outside of building and vents adequately covered.
 - (iv) Block valves connecting relief devices to a system shall be locked in the open position and block valves in manually-fed above ground bypasses shall be locked in the closed position.
- (b) For steel pipelines whose MAOP is determined under § 192.619(c), if the MAOP is 60 p.s.i. (414 kPa) gage or more, the control or relief pressure limit is as follows:

If the MAOP produces a hoop stress that is:	Then the pressure limit is:
Greater than 72 percent of SMYS	MAOP plus 4 percent
Unknown as a percentage of SMYS	A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP

§ 192.740 Pressure regulating, limiting, and overpressure protection--Individual service lines directly connected to regulated gathering or transmission pipelines

- (a) This section applies, except as provided in paragraph (c) of this section, to any service line directly connected to a transmission pipeline or regulated gathering pipeline as determined in §192.8 that is not operated as part of a distribution system.
- (b) Each pressure regulating or limiting device, relief device (except rupture discs), automatic shutoff device, and associated equipment must be inspected and tested at least once every 3 calendar years, not exceeding 39 months, to determine that it is:
 - (1) In good mechanical condition;
 - (2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;
 - (3) Set to control or relieve at the correct pressure consistent with the pressure limits of § 192.197; and to limit the pressure on the inlet of the service regulator to 60 psi (414 kPA) gauge or less in case the upstream regulator fails to function properly; and
 - (4) Properly installed and protected from dirt, liquids, or conditions that might prevent proper operation.
- (c) This section does not apply to equipment installed on:
 - (1) A service line that only serves engines that power irrigation pumps;
 - (2) A service line included in a distribution integrity management plan meeting the requirements of subpart P of this part; or
 - (3) A service line directly connected to either a production or gathering pipeline other than a regulated gathering line as determined in §192.8 of this part.

§ 192.741 Pressure Limiting and Regulating Stations: Telemetry or Recording Gauges

- (a) Each distribution system supplied by more than one district pressure regulating station must be equipped with telemetry or recording pressure gauges to indicate the gas pressure in the district.
- (b) On distribution systems supplied by a single district pressure regulating station, the operator shall determine the necessity of installing telemetry or recording gauges in the district, taking into consideration the number of customers supplied, the operating pressures, the capacity of the installation, and other operating conditions.
- (c) If there are indications of abnormally high or low pressure, the regulator and the auxiliary equipment must be inspected and the necessary measures employed to correct any unsatisfactory operating conditions.

§ 192.743 Pressure Limiting and Regulating Stations: Capacity of Relief Devices

- (a) Pressure relief devices at pressure limiting stations and pressure regulating stations must have sufficient capacity to protect the facilities to which they are connected. Except as provided in § 192.739(b), the capacity must be consistent with the pressure limits of § 192.201(a). This capacity must be determined at intervals not exceeding 15 months, but at least once each calendar year, by testing the devices in place or by review and calculations.
- (b) If review and calculations are used to determine if a device has sufficient capacity, the calculated capacity must be compared with the rated or experimentally determined relieving capacity of the device for the conditions under which it operates. After the initial

calculations, subsequent calculations need not be made if the annual review documents that parameters have not changed to cause the rated or experimentally determined relieving capacity to be insufficient.

- (c) If a relief device is of insufficient capacity, a new or additional device must be installed to provide the capacity required by paragraph (a) of this section.

§ 192.745 Valve Maintenance: Transmission Lines

- (a) Each valve, the use of which may be necessary for the safe operation of a transmission line, must be identified and readily accessible. These valves must be inspected, lubricated when necessary and partially operated at intervals not exceeding 15 months, but at least once each calendar year.
- (b) Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.
- (c) For each remote-control valve (RCV) installed in accordance with § 192.179 or § 192.634, an operator must conduct a point-to-point verification between SCADA system displays and the installed valves, sensors, and communications equipment, in accordance with § 192.631(c) and (e).
- (d) For each alternative equivalent technology installed on an onshore pipeline under § 192.179(e) or (f) or § 192.634 that is manually or locally operated (i.e., not a rupture-mitigation valve (RMV), as that term is defined in § 192.3):
 - (1) Operators must achieve a valve closure time of 30 minutes or less, pursuant to § 192.636(b), through an initial drill and through periodic validation as required in paragraph (d)(2) of this section. An operator must review and document the results of each phase of the drill response to validate the total response time, including confirming the rupture, and valve shut-off time as being less than or equal to 30 minutes after rupture identification.
 - (2) Within each pipeline system and within each operating or maintenance field work unit, operators must randomly select a valve serving as an alternative equivalent technology in lieu of an RMV for an annual 30-minute-total response time validation drill that simulates worst-case conditions for that location to ensure compliance with § 192.636. Operators are not required to close the valve fully during the drill; a minimum 25 percent valve closure is sufficient to demonstrate compliance with drill requirements unless the operator has operational information that requires an additional closure percentage for maintaining reliability. The response drill must occur at least once each calendar year, with intervals not to exceed 15 months. Operators must include in their written procedures the method they use to randomly select which alternative equivalent technology is tested in accordance with this paragraph.
 - (3) If the 30-minute-maximum response time cannot be achieved during the drill, the operator must revise response efforts to achieve compliance with § 192.636 as soon as practicable but no later than 12 months after the drill. Alternative valve shut-off measures must be in place in accordance with paragraph (e) of this section within 7 days of a failed drill.

- (4) Based on the results of response-time drills, the operator must include lessons learned in:
 - (i) Training and qualifications programs;
 - (ii) Design, construction, testing, maintenance, operating, and emergency procedures manuals; and
 - (iii) Any other areas identified by the operator as needing improvement.
- (5) The requirements of this paragraph (d) do not apply to manual valves who, pursuant to § 192.636(g), have been exempted from the requirements of § 192.636(b).
- (e) Each operator must develop and implement remedial measures to correct any valve installed on an onshore pipeline under § 192.179(e) or (f) or § 192.634 that is indicated to be inoperable or unable to maintain effective shut-off as follows:
 - a. Repair or replace the valve as soon as practicable but no later than 12 months after finding that the valve is inoperable or unable to maintain effective shut-off. An operator must request an extension from PHMSA in accordance with § 192.18 if repair or replacement of a valve within 12 months would be economically, technically, or operationally infeasible; and
 - b. Designate an alternative valve acting as an RMV within 7 calendar days of the finding while repairs are being made and document an interim response plan to maintain safety. Such valves are not required to comply with the valve spacing requirements of this part.
- (f) An operator using an ASV as an RMV, in accordance with §§ 192.3, 192.179, 192.634, and 192.636, must document and confirm the ASV shut-in pressures, in accordance with § 192.636(f), on a calendar year basis not to exceed 15 months. ASV shut-in set pressures must be proven and reset individually at each ASV, as required, on a calendar year basis not to exceed 15 months.

§ 192.747 Valve Maintenance: Distribution Systems

- (a) Each valve, the use of which may be necessary for the safe operation of a distribution system must be identified and readily accessible. These valves must be inspected, lubricated when necessary and partially operated at intervals not exceeding 15 months, but at least once each calendar year.
- (b) Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.

§ 192.749 Vault Maintenance

- (a) Each vault housing pressure regulating and pressure limiting equipment and having a volumetric internal content of 200 cubic feet (5.66 cubic meters) or more, must be inspected, at intervals not exceeding 15 months, but at least once each calendar year, to determine that it is in good physical condition and adequately ventilated.
- (b) If gas is found in the vault, the equipment in the vault must be inspected for leaks, and any

leaks found must be repaired.

- (c) The ventilating equipment must also be inspected to determine that it is functioning properly.
- (d) Each vault cover must be inspected to assure that it does not present a hazard to public safety.

§ 192.750 Launcher and receiver safety

Any launcher or receiver used after July 1, 2021, must be equipped with a device capable of safely relieving pressure in the barrel before removal or opening of the launcher or receiver barrel closure or flange and insertion or removal of in-line inspection tools, scrapers, or spheres. An operator must use a device to either: Indicate that pressure has been relieved in the barrel; or alternatively prevent opening of the barrel closure or flange when pressurized, or insertion or removal of in-line devices (e.g. inspection tools, scrapers, or spheres), if pressure has not been relieved.

§ 192.751 Prevention of Accidental Ignition

Each operator shall take steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion, including the following:

- (a) When a hazardous amount of gas is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be provided.
- (b) Gas or electric welding or cutting may not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work.
- (c) Post warning signs, where appropriate.

§ 192.753 Caulked Bell and Spigot Joints

- (a) Each cast iron caulked bell and spigot joint that is subject to pressures of more than 25 p.s.i. (172kPa) gage must be sealed with:
 - (1) A mechanical leak clamp; or
 - (2) A material or device which:
 - (i) Does not reduce flexibility of the joint;
 - (ii) Permanently bonds, either chemically or mechanically, or both, with the bell and spigot metal surfaces or adjacent pipe metal surfaces; and
 - (iii) Seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements of §§ 192.53(a) and (b) and § 192.143.
- (b) Each cast iron caulked bell and spigot joint that is subject to pressures of 25 p.s.i. (172kPa) gage or less and is exposed for any reason must be sealed by a means other than caulking.

§ 192.755 Protecting Cast Iron Pipelines

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

- (a) That segment of the pipeline must be protected, as necessary, against damage during the disturbance by:
 - (1) Vibrations from heavy construction equipment, trains, trucks, buses or blasting;
 - (2) Impact force by vehicles;

- (3) Earth movement;
 - (4) Apparent future excavations near the pipeline; or
 - (5) Other foreseeable outside forces which may subject that segment of the pipeline to bending stress.
- (b) As soon as feasible, appropriate steps must be taken to provide permanent protection for the disturbed segment from damage that might result from external loads, including compliance with applicable requirements of §§ 192.317(a), 192.319, and 192.361(b) - (d).

§192.756 Joining plastic pipe by heat fusion; equipment maintenance and calibration

Each operator must maintain equipment used in joining plastic pipe in accordance with the manufacturer's recommended practices or with written procedures that have been proven by test and experience to produce acceptable joints.

SUBPART N - QUALIFICATION OF PIPELINE PERSONNEL

§ 192.801 Scope

- (a) This subpart prescribes the minimum requirements for operator qualification of individuals performing covered tasks on a pipeline facility.
- (b) For the purpose of this subpart, a covered task is an activity, identified by the operator, that:
 - (1) Is performed on a pipeline facility;
 - (2) Is an operations or maintenance task;
 - (3) Is performed as a requirement of this part; and
 - (4) Affects the operation or integrity of the pipeline.

§ 192.803 Definitions

Abnormal operating condition means a condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:

- (a) Indicate a condition exceeding design limits; or
- (b) Result in a hazard(s) to persons, property, or the environment.

Evaluation means a process, established and documented by the operator, to determine an individual's ability to perform a covered task by any of the following:

- (a) Written examination;
- (b) Oral examination;
- (c) Work performance history review;
- (d) Observation during:
 - (1) Performance on the job,
 - (2) On the job training, or
 - (3) Simulations;
- (e) Other forms of assessment.

Qualified means:

- (1) For an operator defined in § 192.3(1), that an individual can:
 - (a) Perform assigned, covered tasks, and
 - (b) Recognize and react to abnormal operating conditions.
- (2) For an operator defined in § 192.3(2), that an individual has been certified by a training program or institution accredited by the International Accreditors for Continuing Education and Training or other similar accreditation institution, that the individual can:
 - (a) Perform assigned, covered tasks; and
 - (b) Recognize and react to abnormal operating conditions.

§ 192.805 Qualification Program

Each operator shall have and follow a written qualification program. The program shall include provisions to:

- (a) Identify covered tasks;
- (b) Ensure that individuals performing covered tasks are qualified;
- (c) Allow individuals that are not qualified to perform a covered task if directed and observed by an individual that is qualified;
- (d) Evaluate whether an individual's performance of a covered task contributed to an incident as defined in Part 191;
- (e) Determine whether an individual is no longer qualified to perform a covered task and needs to be requalified;
- (f) Communicate changes that affect covered tasks to individuals performing those covered tasks;
- (g) Determine the requalification intervals for covered tasks;
- (h) After December 16, 2004, to ensure the safe operation of pipeline facilities, operators must ensure that individuals performing covered tasks are qualified and have the necessary ability and skills to perform the covered tasks that; and
- (i) After December 16, 2004, notify the Administrator or a state agency participating under 49 U.S.C. Chapter 601 within 20 days if the operator significantly modifies the program after the Administrator or state agency has verified that it complies with this section. Notifications to PHMSA must be submitted in accordance with § 192.18.

§ 192.807 Recordkeeping

Each operator shall maintain records that demonstrate compliance with this subpart.

- (a) Qualification records shall include:
 - (1) Identification of qualified individual(s);
 - (2) Identification of the covered tasks the individual is qualified to perform;
 - (3) Date(s) of current qualification; and
 - (4) Qualification method(s).
- (b) Records supporting an individual's current qualification shall be maintained while the individual is performing the covered task. Records of prior qualification and records of

individuals no longer performing covered tasks shall be retained for a period of five years.

§ 192.809 General

- (a) Operators must have a written qualification program by April 27, 2001. The program must be available for review by the Administrator or by a state agency participating under 49 U.S.C. Chapter 601 if the program is under the authority of that state agency.
- (b) Operators must complete the qualification of individuals performing covered tasks by October 28, 2002.
- (c) Work performance history review may be used as a sole evaluation method for individuals who were performing a covered task prior to October 26, 1999.
- (d) After October 28, 2002, work performance history may not be used as a sole evaluation method.
- (e) After December 16, 2004 observation of on-the-job performance may not be used as the sole method of evaluation.

SUBPART O – GAS TRANSMISSION PIPELINE INTEGRITY MANAGEMENT

§ 192.901 What do the regulations in this subpart cover?

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

§ 192.903 What definitions apply to this subpart?

The following definitions apply to this subpart:

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

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

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

Direct assessment is an integrity assessment method that utilizes a process to evaluate certain threats (*i.e.*, external corrosion, internal corrosion and stress corrosion cracking) to a covered pipeline segment's integrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.

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

- (a) An area defined as
 - (i) A Class 3 location under § 192.5; or
 - (ii) A Class 4 location under § 192.5; or
 - (iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or
 - (iv) Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site.
- (b) The area within a potential impact circle containing--
 - (i) 20 or more buildings intended for human occupancy, unless the exception in paragraph (4) applies; or
 - (ii) An identified site.
- (c) Where a potential impact circle is calculated under either method (1) or (2) to establish a high consequence area, the length of the high consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last

contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy. (See Figure E.I.A. in Appendix E.)

- (d) If in identifying a high consequence area under paragraph (1)(iii) of this definition or paragraph (2)(i) of this definition, the radius of the potential impact circle is greater than 660 feet (200 meters), the operator may identify a high consequence area based on a prorated number of buildings intended for human occupancy within a distance 660 feet (200 meters) from the centerline of the pipeline until December 17, 2006. If an operator chooses this approach, the operator must prorate the number of buildings intended for human occupancy based on the ratio of an area with a radius of 660 feet (200 meters) to the area of the potential impact circle (*i.e.*, the prorated number of buildings intended for human occupancy is equal to $20 \times (660 \text{ feet})$ [or 200 meters] / (potential impact radius in feet [or meters]²).

Identified site means each of the following areas:

- (a) An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive). Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or
- (b) A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. (The days and weeks need not be consecutive). Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks; or
- (c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.

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

Potential impact radius (PIR) means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula $r = 0.69 \times (\text{square root of } (p \times d^2))$, where 'r' is the radius of a circular area in feet surrounding the point of failure, 'p' is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and 'd' is the nominal diameter of the pipeline in inches.

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

Remediation is a repair or mitigation activity an operator takes on a covered segment to limit or reduce the probability of an undesired event occurring or the expected consequences from the event.

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

- (a) *General.* To determine which segments of an operator's transmission pipeline system are covered by this subpart, an operator must identify the high consequence areas. An operator must use method (1) or (2) from the definition in § 192.903 to identify a high

consequence area. An operator may apply one method to its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system. An operator must describe in its integrity management program which method it is applying to each portion of the operator's pipeline system. The description must include the potential impact radius when utilized to establish a high consequence area. (See Appendix E.I. for guidance on identifying high consequence areas.)

- (b)(1) *Identified sites.* An operator must identify an identified site, for purposes of this subpart, from information the operator has obtained from routine operation and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate to the operator that they know of locations that meet the identified site criteria. These public officials could include officials on a local emergency planning commission or relevant Native American tribal officials.
- (2) If a public official with safety or emergency response or planning responsibilities informs an operator that it does not have the information to identify an identified site, the operator must use one of the following sources, as appropriate, to identify these sites.
- (i) Visible marking (e.g., a sign); or
 - (ii) The site is licensed or registered by a Federal, State, or local government agency; or
 - (iii) The site is on a list (including a list on an internet web site) or map maintained by or available from a Federal, State, or local government agency and available to the general public.
- (c) *Newly-identified areas.* When an operator has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions in § 192.903, the operator must complete the evaluation using method (1) or (2). If the segment is determined to meet the definition as a high consequence area, it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified.

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

- (a) *General.* No later than December 17, 2004, an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in § 192.911 and that addresses the risks on each covered transmission pipeline segment. The initial integrity management program must consist, at a minimum, of a framework that describes the process for implementing each program element, how relevant decisions will be made and by whom, a time line for completing the work to implement the program element, and how information gained from experience will be continuously incorporated into the program. The framework will evolve into a more detailed and comprehensive program. An operator must make continual improvements to the program.
- (b) *Implementation Standards.* In carrying out this subpart, an operator must follow the requirements of this subpart and of ASME B31.8S (incorporated by reference, see § 192.7) and its appendices, where specified. An operator may follow an equivalent standard or practice only when the operator demonstrates the alternative standard or practice provides an equivalent level of safety to the public and property. In the event of a conflict between this subpart and ASME B31.8S, the requirements in this subpart control.

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

- (a) *General.* An operator must document any change to its program and the reasons for the change before implementing the change.
- (b) *Notification.* An operator must notify OPS, in accordance with § 192.18, of any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. An operator must provide notification within 30 days after adopting this type of change into its program.

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

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

- (a) An identification of all high consequence areas, in accordance with § 192.905.
- (b) A baseline assessment plan meeting the requirements of §§ 192.919 and 192.921.
- (c) An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (§ 192.917) and to evaluate the merits of additional preventive and mitigative measures (§ 192.935) for each covered segment.
- (d) A direct assessment plan, if applicable, meeting the requirements of § 192.923, and depending on the threat assessed, of §§ 192.925, 192.927, or 192.929.
- (e) Provisions meeting the requirements of § 192.933 for remediating conditions found during an integrity assessment.
- (f) A process for continual evaluation and assessment meeting the requirements of § 192.937.
- (g) If applicable, a plan for confirmatory direct assessment meeting the requirements of § 192.931.
- (h) Provisions meeting the requirements of § 192.935 for adding preventive and mitigative measures to protect the high consequence area.
- (i) A performance plan as outlined in ASME B31.8S, section 9 that includes performance measures meeting the requirements of § 192.945.
- (j) Record keeping provisions meeting the requirements of § 192.947.
- (k) A management of change process as required by § 192.13(d).
- (l) A quality assurance process as outlined in ASME/ANSI B31.8S, section 12.
- (m) A communication plan that includes the elements of ASME B31.8S, Paragraph 850.9 (incorporated by reference, see § 192.7), and that includes procedures for addressing safety concerns raised by:
 - (1) OPS; and
 - (2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.
- (n) Procedures for providing (when requested), by electronic or other means, a copy of

the operator's risk analysis or integrity management program to:

- (1) OPS; and
 - (2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.
- (o) Procedures for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks.
- (p) A process for identification and assessment of newly-identified high consequence areas. (See § 192.905 and § 192.921.)

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

- (a) *General.* ASME/ANSI B31.8S (incorporated by reference, see § 192.7) provides the essential features of a performance-based or a prescriptive integrity management program. An operator that uses a performance-based approach that satisfies the requirements for exceptional performance in paragraph (b) of this section may deviate from certain requirements in this subpart, as provided in paragraph (c) of this section.
- (b) *Exceptional performance.* An operator must be able to demonstrate the exceptional performance of its integrity management program through the following actions:
- (1) To deviate from any of the requirements set forth in paragraph (c) of this section, an operator must have a performance-based integrity management program that meets or exceed the performance-based requirements of ASME/ANSI B31.8S and includes, at a minimum, the following elements:
 - (i) A comprehensive process for risk analysis;
 - (ii) All risk factor data used to support the program;
 - (iii) A comprehensive data integration process;
 - (iv) A procedure for applying lessons learned from assessment of covered pipeline segments to pipeline segments not covered by this subpart;
 - (v) A procedure for evaluating every incident, including its cause, within the operator's sector of the pipeline industry for implications both to the operator's pipeline system and to the operator's integrity management program;
 - (vi) A performance matrix that demonstrates the program has been effective in ensuring the integrity of the covered segments by controlling the identified threats to the covered segments;
 - (vii) Semi-annual performance measures beyond those required in § 192.945 that are part of the operator's performance plan. (See § 192.911(i).) An operator must submit these measures, by electronic or other means, on a semi-annual frequency to OPS in accordance with § 192.951; and
 - (viii) An analysis that supports the desired integrity reassessment interval and the remediation methods to be used for all covered segments.
 - (2) In addition to the requirements for the performance-based plan, an operator must:
 - (i) Have completed at least two integrity assessments on each covered pipeline segment the operator is including under the performance-based approach, and be able to demonstrate that each assessment effectively addressed the identified threats on the covered segment.

- (ii) Remediate all anomalies identified in the more recent assessment according to the requirements in § 192.933, and incorporate the results and lessons learned from the more recent assessment into the operator's data integration and risk assessment.
- (c) *Deviation.* Once an operator has demonstrated that it has satisfied the requirements of paragraph (b) of this section, the operator may deviate from the prescriptive requirements of ASME/ANSI B31.8S and of this subpart only in the following instances.
 - (1) The time frame for reassessment as provided in § 192.939 except that reassessment by some method allowed under this subpart (e.g., confirmatory direct assessment) must be carried out at intervals no longer than seven years;
 - (2) The time frame for remediation as provided in § 192.933 if the operator demonstrates the time frame will not jeopardize the safety of the covered segment.

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

- (a) *Supervisory personnel.* The integrity management program must provide that each supervisor whose responsibilities relate to the integrity management program possesses and maintains a thorough knowledge of the integrity management program and of the elements for which the supervisor is responsible. The program must provide that any person who qualifies as a supervisor for the integrity management program has appropriate training or experience in the area for which the person is responsible.
- (b) *Persons who carry out assessments and evaluate assessment results.* The integrity management program must provide criteria for the qualification of any person
 - (1) Who conducts an integrity assessment allowed under this subpart; or
 - (2) Who reviews and analyzes the results from an integrity assessment and evaluation; or
 - (3) Who makes decisions on actions to be taken based on these assessments.
- (c) *Persons responsible for preventive and mitigative measures.* The integrity management program must provide criteria for the qualification of any person:
 - (1) Who implements preventive and mitigative measures to carry out this subpart, including the marking and locating of buried structures; or
 - (2) Who directly supervises excavation work carried out in conjunction with an integrity assessment.

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

- (a) *Threat identification.* An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME B31.8S (incorporated by reference, see § 192.7), section 2, which are grouped under the following four categories:
 - (1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;
 - (2) Stable threats, such as manufacturing, welding, fabrication, or construction defects;
 - (3) Time independent threats such as third-party damage, mechanical damage,

incorrect operational procedure, weather related and outside force damage to include consideration of seismicity, geology, and soil stability of the area; and

- (4) Human error, such as operational or maintenance mishaps, or design and construction mistakes.
- (b) *Data gathering and integration.* To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME B31.8S, section 4. An operator may request an extension of up to 1 year by submitting a notification to PHMSA at least 90 days before February 26, 2024, in accordance with § 192.18. The notification must include a reasonable and technically justified basis, an up-to-date plan for completing all actions required by this paragraph (b), the reason for the requested extension, current safety or mitigation status of the pipeline segment, the proposed completion date, and any needed temporary safety measures to mitigate the impact on safety. An operator must gather and evaluate the set of data listed in paragraph (b)(1) of this section. The evaluation must analyze both the covered segment and similar non-covered segments, and it must:
- (1) Integrate pertinent information about pipeline attributes to ensure safe operation and pipeline integrity, including information derived from operations and maintenance activities required under this part, and other relevant information, including, but not limited to:
 - (i) Pipe diameter, wall thickness, seam type, and joint factor;
 - (ii) Manufacturer and manufacturing date, including manufacturing data and records;
 - (iii) Material properties including, but not limited to, grade, specified minimum yield strength (SMYS), and ultimate tensile strength;
 - (iv) Equipment properties;
 - (v) Year of installation;
 - (vi) Bending method;
 - (vii) Joining method, including process and inspection results;
 - (viii) Depth of cover;
 - (ix) Crossings, casings (including if shorted), and locations of foreign line crossings and nearby high voltage power lines;
 - (x) Hydrostatic or other pressure test history, including test pressures and test leaks or failures, failure causes, and repairs;
 - (xi) Pipe coating methods (both manufactured and field applied), including the method or process used to apply girth weld coating, inspection reports, and coating repairs;
 - (xii) Soil, backfill;
 - (xiii) Construction inspection reports, including but not limited to:
 - (A) Post backfill coating surveys; and
 - (B) Coating inspection (“jeeping” or “holiday inspection”) reports;

- (xiv) Cathodic protection installed, including, but not limited to, type and location;
- (xv) Coating type;
- (xvi) Gas quality;
- (xvii) Flow rate;
- (xviii) Normal maximum and minimum operating pressures, including maximum allowable operating pressure (MAOP);
- (xix) Class location;
- (xx) Leak and failure history, including any in-service ruptures or leaks from incident reports, abnormal operations, safety-related conditions (both reported and unreported) and failure investigations required by § 192.617, and their identified causes and consequences;
- (xxi) Coating condition;
- (xxii) Cathodic protection (CP) system performance;
- (xxiii) Pipe wall temperature;
- (xxiv) Pipe operational and maintenance inspection reports, including, but not limited to:
 - (A) Data gathered through integrity assessments required under this part, including, but not limited to, in-line inspections, pressure tests, direct assessments, guided wave ultrasonic testing, or other methods;
 - (B) Close interval survey (CIS) and electrical survey results;
 - (C) CP rectifier readings;
 - (D) CP test point survey readings and locations;
 - (E) Alternating current, direct current, and foreign structure interference surveys;
 - (F) Pipe coating surveys, including surveys to detect coating damage, disbanded coatings, or other conditions that compromise the effectiveness of corrosion protection, including, but not limited to, direct current voltage gradient or alternating current voltage gradient inspections;
 - (G) Results of examinations of exposed portions of buried pipelines (e.g., pipe and pipe coating condition, see § 192.459), including the results of any non-destructive examinations of the pipe, seam, or girth weld (i.e. bell hole inspections);
 - (H) Stress corrosion cracking excavations and findings;
 - (I) Selective seam weld corrosion excavations and findings;
 - (J) Any indication of seam cracking; and
 - (K) Gas stream sampling and internal corrosion monitoring results, including cleaning pig sampling results;
- (xxv) External and internal corrosion monitoring;

- (xxvi) Operating pressure history and pressure fluctuations, including an analysis of effects of pressure cycling and instances of exceeding MAOP by any amount;
 - (xxvii) Performance of regulators, relief valves, pressure control devices, or any other device to control or limit operating pressure to less than MAOP;
 - (xxviii) Encroachments;
 - (xxix) Repairs;
 - (xxx) Vandalism;
 - (xxxi) External forces;
 - (xxxii) Audits and reviews;
 - (xxxiii) Industry experience for incident, leak, and failure history;
 - (xxxiv) Aerial photography; and
 - (xxxv) Exposure to natural forces in the area of the pipeline, including seismicity, geology, and soil stability of the area.
- (2) Use validated information and data as inputs, to the maximum extent practicable. If input is obtained from subject matter experts (SME), an operator must employ adequate control measures to ensure consistency and accuracy of information. Control measures may include training of SMEs or the use of outside technical experts (independent expert reviews) to assess the quality of processes and the judgment of SMEs. An operator must document the names and qualifications of the individuals who approve SME inputs used in the current risk assessment.
 - (3) Identify and analyze spatial relationships among anomalous information (e.g., corrosion coincident with foreign line crossings or evidence of pipeline damage where overhead imaging shows evidence of encroachment).
 - (4) Analyze the data for interrelationships among pipeline integrity threats, including combinations of applicable risk factors that increase the likelihood of incidents or increase the potential consequences of incidents.
- (c) *Risk assessment.* An operator must conduct a risk assessment that follows ASME B31.8S, section 5, and that analyzes ~~considers~~ the identified threats and potential consequences of an incident for each covered segment. An operator must ensure the validity of the methods used to conduct the risk assessment considering the incident, leak, and failure history of the pipeline segments and other historical information. Such a validation must ensure the risk assessment methods produce a risk characterization that is consistent with the operator's and industry experience, including evaluations of the cause of past incidents, as determined by root cause analysis or other equivalent means, and include sensitivity analysis of the factors used to characterize both the likelihood of loss of pipeline integrity and consequences of the postulated loss of pipeline integrity. An operator must use the risk assessment to determine additional preventive and mitigative measures needed for each covered segment in accordance with § 192.935 and periodically evaluate the integrity of each covered pipeline segment in accordance with § 192.937. Beginning February 26, 2024, the risk assessment must:
- (1) Analyze how a potential failure could affect high consequence areas;
 - (2) Analyze the likelihood of failure due to each individual threat and each unique combination of threats that interact or simultaneously contribute to risk at a common

- location;
- (3) Account for, and compensate for, uncertainties in the model and the data used in the risk assessment; and
 - (4) Evaluate the potential risk reduction associated with candidate risk reduction activities, such as preventive and mitigative measures, and reduced anomaly remediation and assessment intervals.
- (d) *Plastic Transmission Pipeline.* An operator of a plastic transmission pipeline must assess the threats to each covered segment using the information in sections 4 and 5 of ASME B31.8S, and consider any threats unique to the integrity of plastic pipe, such as poor joint fusion practices, pipe with poor slow crack growth (SCG) resistance, brittle pipe, circumferential cracking, hydrocarbon, softening of the pipe, internal and external loads, longitudinal or lateral loads, proximity to elevated heat sources, and point loading.
- (e) *Actions to address particular threats.* If an operator identifies any of the following threats, the operator must take the following actions to address the threat.
- (1) *Third party damage.* An operator must utilize the data integration required in paragraph (b) of this section and ASME B31.8S, Appendix A-8 to determine the susceptibility of each covered segment to the threat of third-party damage. If an operator identifies the threat of third-party damage, the operator must implement comprehensive additional preventive measures in accordance with § 192.935 and monitor the effectiveness of the preventive measures. If, in conducting a baseline assessment under § 192.921, or a reassessment under § 192.937, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third-party damage may exist in the covered segment. An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration.
 - (2) *Cyclic fatigue.* An operator must analyze and account for whether cyclic fatigue or other loading conditions (including ground movement, and suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, crack, or other defect in the covered segment. The analysis must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the analysis together with the criteria used to determine the significance of the threat(s) to the covered segment to prioritize the integrity baseline assessment or reassessment. Failure stress pressure and crack growth analysis of cracks and crack-like defects must be conducted in accordance with § 192.712. An operator must monitor operating pressure cycles and periodically, but at least every 7 calendar years, with intervals not to exceed 90 months, determine if the cyclic fatigue analysis remains valid or if the cyclic fatigue analysis must be revised based on changes to operating pressure cycles or other loading conditions.
 - (3) *Manufacturing and construction defects.* An operator must analyze the covered segment to determine and account for the risk of failure from manufacturing and construction defects (including seam defects) in the covered segment. The analysis must account for the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects only if the covered segment has been subjected to hydrostatic pressure

testing satisfying the criteria of subpart J of at least 1.25 times MAOP, and the covered segment has not experienced a reportable incident attributed to a manufacturing or construction defect since the date of the most recent subpart J pressure test. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high-risk segment for the baseline assessment or a subsequent reassessment.

- (i) The pipeline segment has experienced a reportable incident, as defined in § 191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, or a construction, installation-, or fabrication-related defect;
 - (ii) MAOP increases; or
 - (iii) The stresses leading to cyclic fatigue increase.
- (4) *Electric Resistance Welded (ERW) pipe.* If a covered pipeline segment contains low frequency ERW pipe, lap welded pipe, pipe with longitudinal joint factor less than 1.0 as defined in § 192.113, or other pipe that satisfies the conditions specified in ASME B31.8S, Appendices A-5.3 and A-5.4, and any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure (including seam cracking and selective seam weld corrosion), or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding 5 years (including abnormal operation as defined in § 192.605(c)), or MAOP has been increased, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high-risk segment for the baseline assessment or a subsequent reassessment. Pipe with seam cracks must be evaluated using fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis to estimate the remaining life of the pipe in accordance with § 192.712. Corrosion. If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in § 192.933), the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's established operating and maintenance procedures under Part 192 for testing and repair.
- (5) *Corrosion.* If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in § 192.933), the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's established operating and maintenance procedures under part 192 for testing and repair.
- (6) *Cracks.* If an operator identifies any crack or crack-like defect (e.g., stress corrosion cracking or other environmentally assisted cracking, seam defects, selective seam weld corrosion, girth weld cracks, hook cracks, and fatigue cracks) on a covered pipeline segment that could adversely affect the integrity of the pipeline, the operator must evaluate, and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar characteristics associated

with the crack or crack-like defect. Similar characteristics may include operating and maintenance histories, material properties, and environmental characteristics. An operator must establish a schedule for evaluating, and remediating, as necessary, the similar pipeline segments that is consistent with the operator's established operating and maintenance procedures under this part for testing and repair.

§ 192.919 What must be in the baseline assessment plan?

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

- (a) Identification of the potential threats to each covered pipeline segment and the information supporting the threat identification. (See §192.917.);
- (b) The methods selected to assess the integrity of the line pipe, including an explanation of why the assessment method was selected to address the identified threats to each covered segment. The integrity assessment method an operator uses must be based on the threats identified to the covered segment. (See § 192.917.) More than one method may be required to address all the threats to the covered pipeline segment;
- (c) A schedule for completing the integrity assessment of all covered segments, including, risk factors considered in establishing the assessment schedule;
- (d) If applicable, a direct assessment plan that meets the requirements of §§ 192.923, and depending on the threat to be addressed, of § 192.925, § 192.927, or § 192.929; and
- (e) A procedure to ensure that the baseline assessment is being conducted in a manner that minimizes environmental and safety risks.

§ 192.921 How is the baseline assessment to be conducted?

- (a) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods for each threat to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (See § 192.917).
 - (1) Internal inspection tool or tools capable of detecting those threats to which the pipeline is susceptible. The use of internal inspection tools is appropriate for threats such as corrosion, deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (e.g., stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493. In addition, an operator must analyze and account for uncertainties in reported results (e.g., tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies;
 - (2) Pressure test conducted in accordance with subpart J of this part. The use of subpart J pressure testing is appropriate for threats such as internal corrosion; external corrosion and other environmentally assisted corrosion mechanisms; manufacturing and related defects threats, including defective pipe and pipe seams; stress corrosion cracking; selective seam weld corrosion; dents; and other forms of mechanical damage. An operator must use the test pressures specified

- in Table 5.6.1-1 of section 5 of ASME B31.8S (incorporated by reference, see § 192.7) to justify an extended reassessment interval in accordance with § 192.939.
- (3) Spike hydrostatic pressure test conducted in accordance with § 192.506. The use of spike hydrostatic pressure testing is appropriate for time-dependent threats such as stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects;
 - (4) Excavation and *in situ* direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), inverse wave field extrapolation (IWEX), radiography, and magnetic particle inspection (MPI);
 - (5) Guided wave ultrasonic testing (GWUT) as described in Appendix F. The use of GWUT is appropriate for internal and external pipe wall loss;
 - (6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and the pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in §§ 192.925, 192.927 and 192.929; or
 - (7) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify PHMSA in advance of using the other technology in accordance with § 192.18.
- (b) *Prioritizing segments.* An operator must prioritize the covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats to each covered segment. The risk analysis must comply with the requirements in § 192.917.
 - (c) *Assessment for particular threats.* In choosing an assessment method for the baseline assessment of each covered segment, an operator must take the actions required in § 192.917(e) to address particular threats that it has identified.
 - (d) *Time period.* An operator must prioritize all the covered segments for assessment in accordance with § 192.917 (c) and paragraph (b) of this section. An operator must assess at least 50% of the covered segments beginning with the highest risk segments, by December 17, 2007. An operator must complete the baseline assessment of all covered segments by December 17, 2012.
 - (e) *Prior assessment.* An operator may use a prior integrity assessment conducted before December 17, 2002 as a baseline assessment for the covered segment, if the integrity assessment meets the baseline requirements in this subpart and subsequent remedial actions to address the conditions listed in § 192.933 have been carried out. In addition, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe in the covered segment according to the requirements of § 192.937 and § 192.939.
 - (f) *Newly identified areas.* When an operator identifies a new high consequence area (see § 192.905), an operator must complete the baseline assessment of the line pipe in the newly

identified high consequence area within ten (10) years from the date the area is identified.

- (g) *Newly installed pipe.* An operator must complete the baseline assessment of a newly installed segment of pipe covered by this subpart within ten (10) years from the date the pipe is installed. An operator may conduct a pressure test in accordance with paragraph (a)(2) of this section, to satisfy the requirement for a baseline assessment.
- (h) *Plastic transmission pipeline.* If the threat analysis required in § 192.917(d) on a plastic transmission pipeline indicates that a covered segment is susceptible to failure from causes other than third-party damage, an operator must conduct a baseline assessment of the segment in accordance with the requirements of this section and of § 192.917. The operator must justify the use of an alternative assessment method that will address the identified threats to the covered segment.
- (i) Baseline assessments for pipeline segments with a reconfirmed MAOP. An integrity assessment conducted in accordance with the requirements of § 192.624(c) may be used as a baseline assessment under this section.

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

- (a) *General.* An operator may use direct assessment either as a primary assessment method or as a supplement to the other assessment methods allowed under this subpart. An operator may only use direct assessment as the primary assessment method to address the identified threats of external corrosion (EC), internal corrosion (IC), and stress corrosion cracking (SCC).
- (b) *Primary method.* An operator using direct assessment as a primary assessment method must have a plan that complies with the requirements in –
 - (1) Section 192.925 and ASME B31.8S (incorporated by reference, see § 192.7), Section 6.4, and NACE SP0502 (incorporated by reference, see § 192.7), if addressing external corrosion (EC).
 - (2) Section 192.927 and NACE SP0206 (incorporated by reference, see § 192.7), , if addressing internal corrosion (IC).
 - (3) Section 192.929 and NACE SP0204 (incorporated by reference, see § 192.7), , if addressing stress corrosion cracking (SCC).
- (c) *Supplemental method.* An operator using direct assessment as a supplemental assessment method for any applicable threat must have a plan that follows the requirements for confirmatory direct assessment in § 192.931.

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

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

- (1) *Preassessment.* In addition to the requirements in ASME B31.8S section 6.4 and NACE SP0502, section 3, the plan's procedures for preassessment must include -
 - (i) Provisions applying more restrictive criteria when conducting ECDA for the first time on a covered segment; and
 - (ii) The basis on which an operator selects at least two different, but complementary indirect assessment tools to assess each ECDA Region. If an operator utilizes an indirect inspection method that is not discussed in Appendix A of NACE SP0502, the operator must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.

- (2) *Indirect inspection.* In addition to the requirements in ASME B31.8S, section 6.4 and NACE SP0502, section 4, the plan's procedures for indirect inspection of the ECDA regions must include -
 - (i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;
 - (ii) Criteria for identifying and documenting those indications that must be considered for excavation and direct examination. Minimum identification criteria include the known sensitivities of assessment tools, the procedures for using each tool, and the approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected;
 - (iii) Criteria for defining the urgency of excavation and direct examination of each indication identified during the indirect examination. These criteria must specify how an operator will define the urgency of excavating the indication as immediate, scheduled or monitored; and
 - (iv) Criteria for scheduling excavation of indications for each urgency level.

- (3) *Direct examination.* In addition to the requirements in ASME B31.8S section 6.4 and NACE SP0502, section 5, the plan's procedures for direct examination of indications from the indirect examination must include -
 - (i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;
 - (ii) Criteria for deciding what action should be taken if either:
 - (A) Corrosion defects are discovered that exceed allowable limits (Section 5.5.2.2 of NACE SP0502), or
 - (B) Root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE SP0502);
 - (iii) Criteria and notification procedures for any changes in the ECDA Plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications; and
 - (iv) Criteria that describe how and on what basis an operator will reclassify and reprioritize any of the provisions that are specified in section 5.9 of NACE SP0502

- (4) *Post assessment and continuing evaluation.* In addition to the requirements in ASME B31.8S section 6.4 and NACE SP0502, section 6, the plan's

procedures for post assessment of the effectiveness of the ECDA process must include -

- (i) Measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion in covered segments; and
- (ii) Criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the covered segment at an interval less than that specified in § 192.939. (See Appendix D of NACE SP0502.)

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

- (a) *Definition.* Internal Corrosion Direct Assessment (ICDA) is a process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO₂, O₂, hydrogen sulfide or other contaminants present in the gas.
- (b) *General requirements.* An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in NACE SP0206 (incorporated by reference, see § 192.7). The Dry Gas Internal Corrosion Direct Assessment (DG-ICDA) process described in this section applies only for a segment of pipe transporting normally dry natural gas (see § 192.3) and not for a segment with electrolytes normally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolytes present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to address internal corrosion effectively and must notify PHMSA in accordance with § 192.18. In the event of a conflict between this section and NACE SP0206, the requirements in this section control.
- (c) *The ICDA plan.* An operator must develop and follow an ICDA plan that meets NACE SP0206 (incorporated by reference, see § 192.7) and that implements all four steps of the DG-ICDA process, including pre-assessment, indirect inspection, detailed examination at excavation locations, and post-assessment evaluation and monitoring. The plan must identify the locations of all ICDA regions within covered segments in the transmission system. An ICDA region is a continuous length of pipe (including weld joints), uninterrupted by any significant change in water or flow characteristics, that includes similar physical characteristics or operating history. An ICDA region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur until a new input introduces the possibility of water entering the pipeline. In cases where a single covered segment is partially located in two or more ICDA regions, the four-step ICDA process must be completed for each ICDA region in which the covered segment is partially located to complete the assessment of the covered segment.
 - (1) *Preassessment.* An operator must comply with NACE SP0206 (incorporated by reference, see § 192.7) in conducting the preassessment step of the ICDA process.
 - (2) *Indirect inspection.* An operator must comply with NACE SP0206 (incorporated by reference, see § 192.7), and the following additional requirements, in conducting the Indirect Inspection step of the ICDA process. An operator must explicitly document the results of its feasibility assessment as required by NACE SP0206,

section 3.3 (incorporated by reference, see § 192.7); if any condition that precludes the successful application of ICDA applies, then ICDA may not be used, and another assessment method must be selected. When performing the indirect inspection, the operator must use actual pipeline-specific data, exclusively. The use of assumed pipeline or operational data is prohibited. When calculating the critical inclination angle of liquid holdup and the inclination profile of the pipeline, the operator must consider the accuracy, reliability, and uncertainty of the data used to make those calculations, including, but not limited to, gas flow velocity (including during upset conditions), pipeline elevation profile survey data (including specific profile at features with inclinations such as road crossings, river crossings, drains, valves, drips, etc.), topographical data, and depth of cover. An operator must select locations for direct examination and establish the extent of pipe exposure needed (i.e., the size of the bell hole), to account for these uncertainties and their cumulative effect on the precise location of predicted liquid dropout.

- (3) *Detailed examination.* An operator must comply with NACE SP0206 (incorporated by reference, see § 192.7) in conducting the detailed examination step of the ICDA process. When an operator first uses ICDA for a covered segment, an operator must identify a minimum of two locations for excavation within each covered segment associated with the ICDA region and must perform a detailed examination for internal corrosion at each location using ultrasonic thickness measurements, radiography, or other generally accepted measurement techniques that can examine for internal corrosion or other threats that are being assessed. One location must be the low point (e.g., sag, drip, valve, manifold, dead-leg) within the covered segment nearest to the beginning of the ICDA region. The second location must be further downstream, within the covered segment, near the end of the ICDA region. Whenever corrosion is found during ICDA at any location, the operator must:
- (i) Evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with § 192.933 if the condition is in a covered segment, or in accordance with §§ 192.485 and 192.714 if the condition is not in a covered segment;
 - (ii) Expand the detailed examination program to determine all locations that have internal corrosion within the ICDA region, and accurately characterize the nature, extent, and root cause of the internal corrosion. In cases where the internal corrosion was identified within the ICDA region but outside the covered segment, the expanded detailed examination program must also include at least two detailed examinations within each covered segment associated with the ICDA region, at the location within the covered segment(s) most likely to have internal corrosion. One location must be the low point (e.g., sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA region. The second location must be further downstream, within the covered segment. In instances of first use of ICDA for a covered segment, where these locations have already been examined in accordance with paragraph (c)(3) of this section, two additional detailed examinations must be conducted within the covered segment; and
 - (iii) Expand the detailed examination program to evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA

region in which the corrosion was found and remediate identified instances of internal corrosion in accordance with either § 192.933 or §§ 192.485 and 192.714, as appropriate.

- (4) Post-assessment evaluation and monitoring. An operator must comply with NACE SP0206 (incorporated by reference, see § 192.7) in performing the post assessment step of the ICDA process. In addition to NACE SP0206, the evaluation and monitoring process must also include—
- (i) An evaluation of the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in § 192.939. An operator must carry out this evaluation within 1 year of conducting an ICDA;
 - (ii) Validation of the flow modeling calculations by comparison of actual locations of discovered internal corrosion with locations predicted by the model (if the flow model cannot be validated, then ICDA is not feasible for the segment); and
 - (iii) Continuous monitoring of each ICDA region that contains a covered segment where internal corrosion has been identified by using techniques such as coupons or ultrasonic (UT) sensors or electronic probes, and by periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this subpart and risk factors specific to the ICDA region. At a minimum, the monitoring frequency must be two times each calendar year, but at intervals not exceeding 7 1/2 months. If an operator finds any evidence of corrosion products in the ICDA region, the operator must take prompt action in accordance with one of the two following required actions, and remediate the conditions the operator finds in accordance with § 192.933 or §§ 192.485 and 192.714, as applicable.
 - (A) Conduct excavations of, and detailed examinations at, locations downstream from where the electrolytes might have entered the pipe to investigate and accurately characterize the nature, extent, and root cause of the corrosion, including the monitoring and mitigation requirements of § 192.478; or
 - (B) Assess the covered segment using another integrity assessment method allowed by this subpart.
- (5) *Other requirements.* The ICDA plan must also include the following:
- (i) Criteria an operator will apply in making key decisions (including, but not limited to, ICDA feasibility, definition of ICDA regions and sub-regions, and conditions requiring excavation) in implementing each stage of the ICDA process; and
 - (ii) Provisions that the analysis be carried out on the entire pipeline in which covered segments are present, except that application of the remediation criteria of § 192.933 may be limited to covered segments.

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

- (a) *Definition.* Stress Corrosion Cracking Direct Assessment (SCCDA) is a process to assess a covered pipe segment for the presence of SCC primarily by systematically gathering and analyzing excavation data for pipe having similar operational characteristics and residing in a similar physical environment.
- (b) *General Requirements.* An operator using direct assessment as an integrity assessment method for addressing SCC in a covered pipeline segment must develop and follow an SCCDA plan that meets NACE SP0204 (incorporated by reference, see § 192.7) and that implements all four steps of the SCCDA process, including pre-assessment, indirect inspection, detailed examination at excavation locations, and post-assessment evaluation and monitoring. As specified in NACE SP0204, SCCDA is complementary with other inspection methods for SCC, such as in-line inspection or hydrostatic testing with a spike test, and it is not necessarily an alternative or replacement for these methods in all instances. Additionally, the plan must provide for—
 - (1) *Data gathering and integration.* An operator's plan must provide for a systematic process to collect and evaluate data for all covered pipeline segments to identify whether the conditions for SCC are present and to prioritize the covered pipeline segments for assessment in accordance with NACE SP0204, sections 3 and 4, and Table 1 (incorporated by reference, see § 192.7). This process must also include gathering and evaluating data related to SCC at all sites an operator excavates while conducting its pipeline operations (both within and outside covered segments) where the criteria in NACE SP0204 (incorporated by reference, see § 192.7) indicate the potential for SCC. This data gathering process must be conducted in accordance with NACE SP0204, section 5.3 (incorporated by reference, see § 192.7), and must include, at a minimum, all data listed in NACE SP0204, Table 2 (incorporated by reference, see § 192.7). Further, the following factors must be analyzed as part of this evaluation:
 - (i) The effects of a carbonate-bicarbonate environment, including the implications of any factors that promote the production of a carbonate-bicarbonate environment, such as soil temperature, moisture, the presence or generation of carbon dioxide, or cathodic protection (CP);
 - (ii) The effects of cyclic loading conditions on the susceptibility and propagation of SCC in both high-pH and near-neutral-pH environments;
 - (iii) The effects of variations in applied CP, such as overprotection, CP loss for extended periods, and high negative potentials;
 - (iv) The effects of coatings that shield CP when disbanded from the pipe; and
 - (v) Other factors that affect the mechanistic properties associated with SCC, including, but not limited to, historical and present-day operating pressures, high tensile residual stresses, flowing product temperatures, and the presence of sulfides.
 - (2) Indirect inspection. In addition to NACE SP0204, the plan's procedures for indirect inspection must include provisions for conducting at least two above ground surveys using the complementary measurement tools most appropriate for the pipeline segment based on an evaluation of integrated data.

- (3) Direct examination. In addition to NACE SP0204, the plan's procedures for direct examination must provide for an operator conducting a minimum of three direct examinations for SCC within the covered pipeline segment spaced at the locations determined to be the most likely for SCC to occur.
- (4) Remediation and mitigation. If SCC is discovered in a covered pipeline segment, an operator must mitigate the threat in accordance with one of the following applicable methods:
 - (i) Removing the pipe with SCC; remediating the pipe with a Type B sleeve; performing hydrostatic testing in accordance with paragraph (b)(4)(ii) of this section; or by grinding out the SCC defect and repairing the pipe. If an operator uses grinding for repair, the operator must also perform the following as a part of the repair procedure: nondestructive testing for any remaining cracks or other defects; a measurement of the remaining wall thickness; and a determination of the remaining strength of the pipe at the repair location that is performed in accordance with § 192.712 and that meets the design requirements of §§ 192.111 and 192.112, as applicable. The pipe and material properties an operator uses in remaining strength calculations must be documented in traceable, verifiable, and complete records. If such records are not available, an operator must base the pipe and material properties used in the remaining strength calculations on properties determined and documented in accordance with § 192.607, if applicable.
 - (ii) Performing a spike pressure test in accordance with § 192.506 based upon the class location of the pipeline segment. The MAOP must be no greater than the test pressure specified in § 192.506(a) divided by: 1.39 for Class 1 locations and Class 2 locations that contain Class 1 pipe that has been uprated in accordance with § 192.611; and 1.50 for all other Class 2 locations and all Class 3 and Class 4 locations. An operator must repair any test failures due to SCC by replacing the pipe segment and re-testing the segment until the pipe passes the test without failures (such as pipe seam or gasket leaks, or a pipe rupture). At a minimum, an operator must repair pipe segments that pass the pressure test but have SCC present by grinding the segment in accordance with paragraph (b)(4)(i) of this section.
- (5) *Post assessment.* An operator's procedures for post-assessment, in addition to the procedures listed in NACE SP0204, sections 6.3, "periodic reassessment," and 6.4, "effectiveness of SCCDA," must include the development of a reassessment plan based on the susceptibility of the operator's pipe to SCC as well as the mechanistic behavior of identified cracking. An operator's reassessment intervals must comply with § 192.939. The plan must include the following factors, in addition to any factors the operator determines appropriate:
 - (i) The evaluation of discovered crack clusters during the direct examination step in accordance with NACE SP0204, sections 5.3.5.7, 5.4, and 5.5 (incorporated by reference, see § 192.7);
 - (ii) Conditions conducive to the creation of a carbonate-bicarbonate environment;
 - (iii) Conditions in the application (or loss) of CP that can create or exacerbate SCC;

- (iv) Operating temperature and pressure conditions, including operating stress levels on the pipe;
- (v) Cyclic loading conditions;
- (vi) Mechanistic conditions that influence crack initiation and growth rates;
- (vii) The effects of interacting crack clusters;
- (viii) The presence of sulfides; and
- (ix) Disbonded coatings that shield CP from the pipe.

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

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

- (a) *Threats.* An operator may only use CDA on a covered segment to identify damage resulting from external corrosion or internal corrosion.
- (b) *External corrosion plan.* An operator's CDA plan for identifying external corrosion must comply with § 192.925 with the following exceptions.
 - (1) The procedures for indirect examination may allow use of only one indirect examination tool suitable for the application.
 - (2) The procedures for direct examination and remediation must provide that
 - (i) All immediate action indications must be excavated for each ECDA region; and
 - (ii) At least one high risk indication that meets the criteria of scheduled action must be excavated in each ECDA region.
- (c) *Internal corrosion plan.* An operator's CDA plan for identifying internal corrosion must comply with § 192.927 except that the plan's procedures for identifying locations for excavation may require excavation of only one high risk location in each ICDA region.
- (d) *Defects requiring near-term remediation.* If an assessment carried out under paragraph (b) or (c) of this section reveals any defect requiring remediation prior to the next scheduled assessment, the operator must schedule the next assessment in accordance with NACE SP0502 (incorporated by reference, see § 192.7), section 6.2 and 6.3. If the defect requires immediate remediation, then the operator must reduce pressure consistent with § 192.933 until the operator has completed reassessment using one of the assessment techniques allowed in § 192.937.

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

- (a) *General requirements.* An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis is not available, an operator must obtain the undocumented data through § 192.607. Until documented material properties are available, the operator must use the conservative assumptions in either § 192.712(e)(2) or, if appropriate following a pressure

test, in § 192.712(d)(3).

(1) *Temporary pressure reduction.*

- (i) If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must reduce the operating pressure to one of the following:
 - (A) A level not exceeding 80 percent of the operating pressure at the time the condition was discovered;
 - (B) A level not exceeding the predicted failure pressure times the design factor for the class location in which the affected pipeline is located; or
 - (C) A level not exceeding the predicted failure pressure divided by 1.1.
- (ii) An operator must determine the predicted failure pressure in accordance with § 192.712. An operator must notify PHMSA in accordance with § 192.18 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) or (d) of this section and cannot provide safety through a temporary reduction in operating pressure or other action. The operator must document and keep records of the calculations and decisions used to determine the reduced operating pressure, and the implementation of the actual reduced operating pressure, for a period of 5 years after the pipeline has been remediated.

(2) *Long-term pressure reduction.* When a pressure reduction exceeds 365 days, an operator must notify PHMSA under § 192.18 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline.

(b) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. For the purposes of this section, a condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable. In cases where a determination is not made within the 180-day period, the operator must notify PHMSA, in accordance with § 192.18, and provide an expected date when adequate information will become available. Notification to PHMSA does not alleviate an operator from the discovery requirements of this paragraph (b).

(c) *Schedule for evaluation and remediation.* An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME B31.8S (incorporated by reference, see § 192.7), section 7, Figure 7.2.1-1. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.

(d) *Special requirements for scheduling remediation.*

(1) *Immediate repair conditions.* An operator's evaluation and remediation schedule

must follow ASME B31.8S, section 7 (incorporated by reference, see § 192.7) in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

- (i) A metal loss anomaly where a calculation of the remaining strength of the pipe shows a predicted failure pressure determined in accordance with § 192.712(b) less than or equal to 1.1 times the MAOP at the location of the anomaly.
 - (ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) that has metal loss, cracking, or a stress riser, unless engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.
 - (iii) Metal loss greater than 80 percent of nominal wall regardless of dimensions.
 - (iv) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.25 times the MAOP.
 - (v) A crack or crack-like anomaly meeting any of the following criteria:
 - (A) Crack depth plus any metal loss is greater than 50 percent of pipe wall thickness;
 - (B) Crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth; or
 - (C) The crack or crack-like anomaly has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.25 times the MAOP.
 - (vi) An indication or anomaly that, in the judgment of the person designated by the operator to evaluate the assessment results, requires immediate action.
- (2) *One-year conditions.* Except for conditions listed in paragraph (d)(1) and (d)(3) of this section, an operator must remediate any of the following within one year of discovery of the condition:
- (i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless engineering analyses performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.
 - (ii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld, unless engineering analyses performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.

- (iii) A dent located between the 4 o'clock and 8 o'clock positions (lower 1/3 of the pipe) that has metal loss, cracking, or a stress riser, unless engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.
 - (iv) Metal loss anomalies where a calculation of the remaining strength of the pipe at the location of the anomaly shows a predicted failure pressure, determined in accordance with § 192.712(b), less than 1.39 times the MAOP for Class 2 locations, and less than 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME B31.8S (incorporated by reference, see § 192.7), section 7, Figure 4, in accordance with paragraph (c) of this section.
 - (v) Metal loss that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or could affect a girth weld, that has a predicted failure pressure, determined in accordance with § 192.712(b), of less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.
 - (vi) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d), is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.
 - (vii) A crack or crack-like anomaly that has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.
- (3) *Monitored conditions.* An operator is not required by this section to schedule remediation of the following less severe conditions but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation. Monitored indications are the least severe and do not require an operator to examine and evaluate them until the next scheduled integrity assessment interval, but if an anomaly is expected to grow to dimensions or have a predicted failure pressure (with a safety factor) meeting a 1-year condition prior to the next scheduled assessment, then the operator must repair the condition:
- (i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the pipe) and for which engineering analyses of the dent, performed in accordance with § 192.712(c), demonstrate critical strain levels are not exceeded.

- (ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and for which engineering analyses of the dent, performed in accordance with § 192.712(c), demonstrate critical strain levels are not exceeded.
 - (iii) A dent with a depth greater than 2% of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal or helical (spiral) seam weld, and for which engineering analyses, performed in accordance with § 192.712(c), of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.
 - (iv) A dent that has metal loss, cracking, or a stress riser, and where engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.
 - (v) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.
 - (vi) A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.
- (e) In situ direct examination of crack defects. Whenever an operator finds conditions that require the pipeline to be repaired, in accordance with this section, an operator must perform a direct examination of known locations of cracks or crack-like defects using technology that has been validated to detect tight cracks (equal to or less than 0.008 inches crack opening), such as inverse wave field extrapolation (IWEX), phased array ultrasonic testing (PAUT), ultrasonic testing (UT), or equivalent technology. "In situ" examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection for accuracy of the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations.

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

- (a) *General Requirements.*
 - (1) An operator must take additional measures beyond those already required by this part to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. Such additional measures must be based on

the risk analyses required by § 192.917. Measures that operators must consider in the analysis, if necessary, to prevent or mitigate the consequences of a pipeline failure include, but are not limited to:

- (i) Correcting the root causes of past incidents to prevent recurrence;
 - (ii) Establishing and implementing adequate operations and maintenance processes that could increase safety;
 - (iii) Establishing and deploying adequate resources for the successful execution of preventive and mitigative measures;
 - (iv) Installing automatic shut-off valves or remote-control valves;
 - (v) Installing pressure transmitters on both sides of automatic shut-off valves and remote-control valves that communicate with the pipeline control center;
 - (vi) Installing computerized monitoring and leak detection systems;
 - (vii) Replacing pipe segments with pipe of heavier wall thickness or higher strength;
 - (viii) Conducting additional right-of-way patrols;
 - (ix) Conducting hydrostatic tests in areas where pipe material has quality issues or lost records;
 - (x) Testing to determine material mechanical and chemical properties for unknown properties that are needed to assure integrity or substantiate MAOP evaluations, including material property tests from removed pipe that is representative of the in-service pipeline;
 - (xi) Re-coating damaged, poorly performing, or disbonded coatings;
 - (xii) Performing additional depth-of-cover surveys at roads, streams, and rivers;
 - (xiii) Remediating inadequate depth-of-cover;
 - (xiv) Providing additional training to personnel on response procedures and conducting drills with local emergency responders; and
 - (xv) Implementing additional inspection and maintenance programs.
- (2) Operators must document the risk analysis, the preventive and mitigative measures considered, and the basis for implementing or not implementing any preventive and mitigative measures considered, in accordance with § 192.947(d).
- (b) *Third Party Damage and Outside Force Damage.*
- (1) *Third party damage.* An operator must enhance its damage prevention program, as required under § 192.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures to an existing damage prevention program include, at a minimum -
- (i) Using qualified personnel (see § 192.915) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.
 - (ii) Collecting in a central database information that is location specific on excavation damage that occurs in covered and non-covered segments in

the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under Part 191.

- (iii) Participating in one-call systems in locations where covered segments are present.
 - (iv) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE SP0502 (incorporated by reference, see § 192.7). An operator must excavate, and remediate, in accordance with ASME B31.8S and §192.933 any indication of coating holidays or discontinuity warranting direct examination.
- (2) *Outside force damage.* If an operator determines that outside force (e.g., earth movement, loading, longitudinal, or lateral forces, seismicity of the area, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include increasing the frequency of aerial, foot or other methods of patrols; adding external protection; reducing external stress; relocating the line; or inline inspections with geospatial and deformation tools. *Automatic shut-off valves (ASV) or Remote-control valves (RCV).* If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors - swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.
- (c) *Risk analysis for gas releases and protection against ruptures.* If an operator determines, based on a risk analysis, that a rupture-mitigation valve (RMV) or alternative equivalent technology would be an efficient means of adding protection to a high-consequence area (HCA) in the event of a gas release, an operator must install the RMV or alternative equivalent technology. In making that determination, an operator must, at least, evaluate the following factors—timing of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel. An RMV or alternative equivalent technology installed under this paragraph must meet all of the other applicable requirements in this part.
- (d) *Pipelines operating below 30% SMYS.* An operator of a transmission pipeline operating below 30% SMYS located in a high consequence area must follow the requirements in paragraphs (d)(1) and (d)(2) of this section. An operator of a transmission pipeline operating below 30% SMYS located in a Class 3 or Class 4 area but not in a high consequence area must follow the requirements in paragraphs (d)(1), (d)(2) and (d)(3) of this section.
- (1) Apply the requirements in paragraphs (b)(1)(i) and (b)(1)(iii) of this section to the pipeline; and

- (2) Either monitor excavations near the pipeline, or conduct patrols as required by § 192.705 of the pipeline at bi-monthly intervals. If an operator finds any indication of unreported construction activity, the operator must conduct a follow up investigation to determine if mechanical damage has occurred.
- (3) Perform instrumented leak surveys using leak detector equipment at least twice each calendar year, at intervals not exceeding 7 1/2 months. For unprotected pipelines or cathodically protected pipe where electrical surveys are impractical, instrumented leak surveys must be performed at least four times each calendar year, at intervals not exceeding 4 1/2 months. Electrical surveys are indirect assessments that include close interval surveys, alternating current voltage gradient surveys, direct current voltage gradient surveys, or their equivalent.
- (e) *Plastic transmission pipeline.* An operator of a plastic transmission pipeline must apply the requirements in paragraphs (b)(1)(i), (b)(1)(iii) and b(1)(iv) of this section to the covered segments of the pipeline.
- (f) *Periodic evaluations.* Risk analyses and assessments conducted under paragraph (c) of this section must be reviewed by the operator and certified by a senior executive of the company, for operational matters that could affect rupture-mitigation processes and procedures. Review and certification must occur once per calendar year, with the period between reviews not to exceed 15 months, and must also occur within 3 months of an incident or safety-related condition, as those terms are defined at §§ 191.3 and 191.23, respectively.

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

- (a) *General.* After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in § 192.939 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph of this section. An operator must reassess a covered segment on which a prior assessment is credited as a baseline under § 192.921(e) by no later than December 172009. An operator must reassess a covered segment on which a baseline assessment is conducted during the baseline period specified in § 192.921(d) by no later than seven years after the baseline assessment of that covered segment unless the evaluation under paragraph (b) of this section indicates earlier reassessment.
- (b) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in § 192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in §192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§ 192.917), and decisions about remediation (§ 192.933) and additional preventive and mitigative actions (§ 192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.
- (c) *Assessment methods.* In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in the covered segment by applying one or more of the following methods for each threat to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified on the covered segment (see § 192.917).
 - (1) *Internal inspection tools.* When performing an assessment using an in-line

inspection tool, an operator must comply with the following requirements:

- (i) Perform the in-line inspection in accordance with § 192.493;
 - (ii) Select a tool or combination of tools capable of detecting the threats to which the pipeline segment is susceptible such as corrosion, deformation and mechanical damage (e.g. dents, gouges and grooves), material cracking and crack-like defects (e.g. stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible; and
 - (iii) Analyze and account for uncertainties in reported results (e.g., tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies.
- (2) *Pressure test conducted in accordance with subpart J of this part.* The use of pressure testing is appropriate for threats such as: Internal corrosion; external corrosion and other environmentally assisted corrosion mechanisms; manufacturing and related defects threats, including defective pipe and pipe seams; stress corrosion cracking; selective seam weld corrosion; dents; and other forms of mechanical damage. An operator must use the test pressures specified in table 3 of section 5 of ASME B31.8S (incorporated by reference, see § 192.7) to justify an extended reassessment interval in accordance with § 192.939.
 - (3) *Spike hydrostatic pressure test in accordance with § 192.506.* The use of spike hydrostatic pressure testing is appropriate for time-dependent threats such as: Stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects;
 - (4) Excavation and *in situ* direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), inverse wave field extrapolation (IWEX), radiography, or magnetic particle inspection (MPI);
 - (5) Guided wave ultrasonic testing (GWUT) as described in Appendix F. The use of GWUT is appropriate for internal and external pipe wall loss;
 - (6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in §§ 192.925, 192.927, and 192.929;
 - (7) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify PHMSA in advance of using the

other technology in accordance with § 192.18; or

- (8) Confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than 7 calendar years. An operator using this reassessment method must comply with § 192.931.
- (d) *MAOP reconfirmation assessments.* An integrity assessment conducted in accordance with the requirements of § 192.624(c) may be used as a reassessment under this section.

§ 192.939 What are the required reassessment intervals?

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

- (a) *Pipelines operating at or above 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is 7 calendar years. Operators may request a 6-month extension of the 7-calendar-year reassessment interval if the operator submits written notice to OPS, in accordance with § 192.18, with sufficient justification of the need for the extension. If an operator establishes a reassessment interval that is greater than 7 calendar years, the operator must, within the 7-calendar-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with § 192.931. The table that follows this section sets forth the maximum allowed reassessment intervals.
 - (1) *Pressure test or internal inspection or other equivalent technology.* An operator that uses pressure testing or internal inspection as an assessment method must establish the reassessment interval for a covered pipeline segment by -
 - (i) Basing the interval on the identified threats for the covered segment (see § 192.917) and on the analysis of the results from the last integrity assessment and from the data integration and risk assessment required by § 192.917; or
 - (ii) Using the intervals specified for different stress levels of pipeline (operating at or above 30% SMYS) listed in ASME B31.8S (incorporated by reference, see § 192.7), Table 5.6.1-1 of Section 5.
 - (2) *External Corrosion Direct Assessment.* An operator that uses ECDA that meets the requirements of this subpart must determine the reassessment interval according to the requirements in paragraphs 6.2 and 6.3 of NACE SP0502 (incorporated by reference, see § 192.7).
 - (3) *Internal Corrosion or SCC Direct Assessment.* An operator that uses ICDA or SCCDA in accordance with the requirements of this subpart must determine the reassessment interval according to the following method. However, the reassessment interval cannot exceed those specified for direct assessment in ASME B31.8S, Table 5.6.1-1 of Section 5.
 - (i) Determine the largest defect most likely to remain in the covered segment and the corrosion rate appropriate for the pipe, soil and protection conditions;
 - (ii) Use the largest remaining defect as the size of the largest defect discovered in the SCC or ICDA segment; and
 - (iii) Estimate the reassessment interval as half the time required for the

largest defect to grow to a critical size.

- (b) *Pipelines Operating Below 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating below 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is 7 calendar years. Operators may request a 6-month extension of the 7-calendar-year reassessment interval if the operator submits written notice to OPS in accordance with §192.18. The notice must include sufficient justification of the need for the extension. An operator must establish reassessment by at least one of the following:
- (1) Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in paragraph (a)(1) of this section except that the stress level referenced in paragraph (a)(1)(ii) of this section would be adjusted to reflect the lower operating stress level. If an established interval is more than 7 calendar years, an operator must conduct by the seventh calendar year of the interval either a confirmatory direct assessment in accordance with § 192.931, or a low stress reassessment in accordance with § 192.941.
 - (2) Reassessment by ECDA following the requirements in paragraph (a)(2) of this section.
 - (3) Reassessment by ICDA or SCCDA following the requirements in paragraph (a)(3) of this section.
 - (4) Reassessment by confirmatory direct assessment at 7-year intervals in accordance with § 192.931, with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this section by year 20 of the interval.
 - (5) Reassessment by the low stress assessment method at 7-year intervals in accordance with § 192.941 with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this section by year 20 of the interval.
 - (6) The following table sets forth the maximum reassessment intervals. Also refer to Appendix E.ii for guidance on Assessment Methods and Assessment Schedule for Transmission Pipelines Operating Below 30% SMYS. In case of conflict between the rule and the guidance in the Appendix, the requirements of the rule control. An operator must comply with the following requirements in establishing a reassessment interval for a covered segment:

Maximum Reassessment Interval			
Assessment Method	Pipeline operating at or above 50% SMYS	Pipeline operating at or above 30% SMYS, up to 50% SMYS	Pipeline operating below 30% SMYS
Internal Inspection Tool, Pressure Test or Direct Assessment	10 years(*)	15 years(*)	20 years(**)
Confirmatory Direct Assessment	7 years	7 years	7 years

Low stress Reassessment	Not applicable	Not applicable	7 years + ongoing actions specified in § 192.941
-------------------------	----------------	----------------	--

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

§ 192.941 What is a low stress reassessment?

- (a) *General.* An operator of a transmission line that operates below 30% SMYS may use the following method to reassess a covered segment in accordance with § 192.939. This method of reassessment addresses the threats of external and internal corrosion. The operator must have conducted a baseline assessment of the covered segment in accordance with the requirements of §§ 192.919 and 192.921.
- (b) *External Corrosion.* An operator must take one of the following actions to address external corrosion on the low stress covered segment.
 - (1) *Cathodically Protected Pipe.* To address the threat of external corrosion on cathodically protected pipe in a covered segment, an operator must perform an indirect assessment on the covered segment at least once every 7 calendar years. The indirect assessment must be conducted using one of the following means: indirect examination method, such as a close interval survey; alternating current voltage gradient survey; direct current voltage gradient survey; or the equivalent of any of these methods. An operator must evaluate the cathodic protection and corrosion threat for the covered segment and include the results of each indirect assessment as part of the overall evaluation. This evaluation must also include, at a minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
 - (2) *Unprotected Pipe or Cathodically Protected Pipe Where Electrical Surveys are Impractical.* If an external corrosion assessment is impractical on the covered segment an operator must -
 - (i) Conduct leakage surveys as required by § 192.706 at 4-month intervals; and
 - (ii) Every 18 months, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
- (c) *Internal Corrosion.* To address the threat of internal corrosion on a covered segment, an operator must -
 - (1) Conduct a gas analysis for corrosive agents at least once each calendar year;
 - (2) Conduct periodic testing of fluids removed from the segment. At least once each calendar year test the fluids removed from each storage field that may affect a covered segment; and
 - (3) At least every seven (7) years, integrate data from the analysis and testing required by paragraphs (c)(1) - (c)(2) with applicable internal corrosion leak records, incident reports, safety-related condition reports, repair records, patrol records, exposed pipe reports, and test records, and define and implement appropriate remediation actions.

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

- (a) *Waiver from reassessment interval in limited situations.* In the following limited instances, OPS may allow a waiver from a reassessment interval required by § 192.939 if OPS finds a waiver would not be inconsistent with pipeline safety.
 - (1) *Lack of internal inspection tools.* An operator who uses internal inspection as an assessment method may be able to justify a longer reassessment period for a covered segment if internal inspection tools are not available to assess the line pipe. To justify this, the operator must demonstrate that it cannot obtain the internal inspection tools within the required reassessment period and that the actions the operator is taking in the interim ensure the integrity of the covered segment.
 - (2) *Maintain product supply.* An operator may be able to justify a longer reassessment period for a covered segment if the operator demonstrates that it cannot maintain local product supply if it conducts the reassessment within the required interval.
- (b) *How to apply.* If one of the conditions specified in paragraph (a)(1) or (a)(2) of this section applies, an operator may seek a waiver of the required reassessment interval. An operator must apply for a waiver in accordance with 49 U.S.C. 60118(c), at least 180 days before the end of the required reassessment interval, unless local product supply issues make the period impractical. If local product supply issues make the period impractical, an operator must apply for the waiver as soon as the need for the waiver becomes known.

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

§ 192.947 What records must an operator keep?

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

- (a) A written integrity management program in accordance with § 192.907;
- (b) Documents supporting the threat identification and risk assessment in accordance with § 192.917;
- (c) A written baseline assessment plan in accordance with § 192.919;
- (d) Documents to support any decision, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents include those developed and used in support of

any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements;

- (e) Documents that demonstrate personnel have the required training, including a description of the training program, in accordance with § 192.915;
- (f) Schedule required by § 192.933 that prioritizes the conditions found during an assessment for evaluation and remediation, including technical justifications for the schedule.
- (g) Documents to carry out the requirements in §§ 192.923 through 192.929 for a direct assessment plan;
- (h) Documents to carry out the requirements in § 192.931 for confirmatory direct assessment;
- (i) Verification that an operator has provided any documentation or notification required by this subpart to be provided to OPS, and when applicable, a State authority with which OPS has an interstate agent agreement, and a State or local pipeline safety authority that regulates a covered pipeline segment within that State.

§ 192.949 [Removed and Reserved]

§ 192.951 Where does an operator file a report?

An operator must file any report required by this subpart to the Information Resources Manager through the online reporting system provided by PHMSA for electronic reporting in accordance with § 191.7 of this Code.

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?

- (a) *General.* Unless exempted in paragraph (b) of this section 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 this subpart.
- (b) *Exceptions.* This subpart does not apply to:
- (1) Individual service lines directly connected to a production line or a gathering line other than a regulated onshore gathering line as determined in §192.8;
 - (2) Individual service lines directly connected to either a transmission or regulated gathering pipeline and maintained in accordance with §192.740(a) and (b); and
 - (3) Master meter systems.

§ 192.1005 What must a gas distribution operator (other than a 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 (including atmospheric corrosion), natural forces, excavation damage, other outside force damage, material or welds, equipment failure, incorrect operations, and other issues 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 incident and leak history, corrosion control records (including atmospheric corrosion 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 [Removed and Reserved]

§ 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 small LPG operator do to implement this subpart?

- (a) *General.* No later than August 2, 2011, a small LPG operator must develop and implement an IM program that includes a written IM plan as specified in paragraph (b) of this section. The IM program for these pipelines should reflect the relative simplicity of these types of pipelines.
- (b) *Elements.* A written integrity management plan must address, at a minimum, the following elements:
 - (1) *Knowledge.* The operator must demonstrate knowledge of its pipeline, which, to the extent known, should include the approximate location and material of its pipeline. The operator must identify additional information needed and provide a plan for gaining knowledge over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).
 - (2) *Identify threats.* The operator must consider, at minimum, the following categories of threats (existing and potential): corrosion (including atmospheric corrosion), natural forces, excavation damage, other outside force damage, material or weld failure, equipment failure, and incorrect operation.
 - (3) *Rank risks.* The operator must evaluate the risks to its pipeline and estimate the relative importance of each identified threat.
 - (4) *Identify and implement measures to mitigate risks.* The operator must determine and implement measures designed to reduce the risks from failure of its pipeline.
 - (5) *Measure performance, monitor results, and evaluate effectiveness.* The operator must monitor, as a performance measure, the number of leaks eliminated or repaired on its pipeline and their causes.
 - (6) *Periodic evaluation and improvement.* The operator must determine the appropriate period for conducting IM program evaluations based on the complexity of its

pipeline and changes in factors affecting the risk of failure. An operator must re-evaluate its entire program at least every five years. The operator must consider the results of the performance monitoring in these evaluations.

- (c) *Records.* The operator must maintain, for a period of at least 10 years, the following records:
- (1) A written IM plan in accordance with this section, including superseded IM plans;
 - (2) Documents supporting threat identification; and
 - (3) Documents showing the location and material of all piping and appurtenances that are installed after the effective date of the operator's IM program and, to the extent known, the location and material of all pipe and appurtenances that were existing on the effective date of the operator's program.

APPENDIX A TO PART 192 - RESERVED

APPENDIX B TO PART 192 - QUALIFICATION OF PIPE AND COMPONENTS

I. List of Specifications

A. Listed Pipe Specifications

API Spec 5L—Steel pipe, “Line Pipe” (incorporated by reference, see § 192.7).

ASTM A53/A53M—Steel pipe, “Standard Specification for Pipe, Steel Black and Hot-Dipped, Zinc-Coated, Welded and Seamless” (incorporated by reference, see § 192.7).

ASTM A106/A-106M—Steel pipe, “Standard Specification for Seamless Carbon Steel Pipe for High Temperature Service” (incorporated by reference, see § 192.7).

ASTM A333/A333M—Steel pipe, “Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service” (incorporated by reference, see § 192.7).

ASTM A381—Steel pipe, “Standard Specification for Metal-Arc-Welded Steel Pipe for Use with High-Pressure Transmission Systems” (incorporated by reference, see § 192.7).

ASTM A671/A671M—Steel pipe, “Standard Specification for Electric-Fusion-Welded Pipe for Atmospheric and Lower Temperatures” (incorporated by reference, see § 192.7).

ASTM A672/A672M-09—Steel pipe, “Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures” (incorporated by reference, see § 192.7).

ASTM A691/A691M-09—Steel pipe, “Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High Pressure Service at High Temperatures” (incorporated by reference, see § 192.7).

ASTM D2513 “Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings” (incorporated by reference, see § 192.7).

ASTM D 2517-00—Thermosetting plastic pipe and tubing, “Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings” (incorporated by reference, see § 192.7).

ASTM F2785-12 “Standard Specification for Polyamide 12 Gas Pressure Pipe, Tubing, and Fittings” (PA-12) (incorporated by reference, see § 192.7).

ASTM F2817-10 “Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair” (incorporated by reference, see § 192.7).

ASTM F2945-12a “Standard Specification for Polyamide 11 Gas Pressure Pipe, Tubing, and Fittings” (PA-11) (incorporated by reference, see § 192.7).

B. Other Listed Specifications for Components

ASME B16.40–2008 “Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems” (incorporated by reference, see § 192.7).

ASTM D2513 “Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings” (incorporated by reference, see § 192.7).

ASTM D 2517–00—Thermosetting plastic pipe and tubing, “Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings” (incorporated by reference, see § 192.7).

ASTM F2785–12 “Standard Specification for Polyamide 12 Gas Pressure Pipe, Tubing, and Fittings” (PA–12) (incorporated by reference, see § 192.7).

ASTM F2945–12a “Standard Specification for Polyamide 11 Gas Pressure Pipe, Tubing, and Fittings” (PA–11) (incorporated by reference, see § 192.7).

ASTM F1055–98 (2006) “Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing” (incorporated by reference, see § 192.7).

ASTM F1924–12 “Standard Specification for Plastic Mechanical Fittings for Use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing” (incorporated by reference, see § 192.7).

ASTM F1948–12 “Standard Specification for Metallic Mechanical Fittings for Use on Outside Diameter Controlled Thermoplastic Gas Distribution Pipe and Tubing” (incorporated by reference, see § 192.7).

ASTM F1973–13 “Standard Specification for Factory Assembled Anodeless Risers and Transition Fittings in Polyethylene (PE) and Polyamide 11 (PA 11) and Polyamide 12 (PA 12) Fuel Gas Distribution Systems” (incorporated by reference, see § 192.7).

ASTM F 2600–09 “Standard Specification for Electrofusion Type Polyamide–11 Fittings for Outside Diameter Controlled Polyamide–11 Pipe and Tubing” (incorporated by reference, see § 192.7).

ASTM F2145–13 “Standard Specification for Polyamide 11 (PA 11) and Polyamide 12 (PA12) Mechanical Fittings for Use on Outside Diameter Controlled Polyamide 11 and Polyamide 12 Pipe and Tubing” (incorporated by reference, see § 192.7).

ASTM F2767–12 “Specification for Electrofusion Type Polyamide–12 Fittings for Outside Diameter Controlled Polyamide–12 Pipe and Tubing for Gas Distribution” (incorporated by reference, see § 192.7).

ASTM F2817–10 “Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair” (incorporated by reference, see § 192.7).

APPENDIX C TO PART 192 - QUALIFICATION OF WELDERS FOR LOW STRESS LEVEL PIPE

I. Basic Test

The test is made on pipe 12 inches (305 millimeters) or less in diameter. The test weld must be made with the pipe in a horizontal fixed position so that the test weld includes at least one section of overhead position welding. The beveling, root opening and other details must conform to the specifications of the procedure under which the welder is being qualified. Upon completion, the test weld is cut into four coupons and subjected to a root bend test. If, as a result of this test, two or more of the four coupons develop a crack in the weld material or between the weld material and base metal, that is more than 1/8 inch (3.2 millimeters) long in any direction, the weld is unacceptable. Cracks that occur on the corner of the specimen during testing are not considered. A welder who successfully passes a butt-weld qualification test under this section shall be qualified to weld on all pipe diameters less than or equal to 12 inches.

II. Additional Tests for Welders of Service Line Connections to Mains

A service line connection fitting is welded to a pipe section with the same diameter as a typical main. The weld is made in the same position as it is made in the field. The weld is unacceptable if it shows a serious undercutting or if it has rolled edges. The weld is tested by attempting to break the fitting off the run pipe. The weld is unacceptable if it breaks and shows incomplete fusion, overlap, or poor penetration at the junction of the fitting and run pipe.

III. Periodic Tests for Welders of Small Service Lines

Two samples of the welder's work, each about 8 inches (203 millimeters) long with the weld located approximately in the center, are cut from steel service line and tested as follows:

- (1) One sample is centered in a guided bend testing machine and bent to the contour of the die for a distance of 2 inches (51 millimeters) on each side of the weld. If the sample shows any breaks or cracks after removal from the bending machine, it is unacceptable.
- (2) The ends of the second sample are flattened and the entire joint subjected to a tensile strength test. If failure occurs adjacent to or in the weld metal, the weld is unacceptable. If a tensile strength testing machine is not available, this sample must also pass the bending test prescribed in Subparagraph (1) of this paragraph.

APPENDIX D TO PART 192 - CRITERIA FOR CATHODIC PROTECTION AND DETERMINATION OF MEASUREMENTS

I. Criteria for Cathodic Protection

A. *Steel, cast iron, and ductile iron structures*

- (1) A negative (cathodic) voltage of at least 0.85 volt, with reference to a saturated copper-copper sulfate half-cell. Determination of this voltage must be made with the protective current applied, and in accordance with Sections II and IV of this Appendix.
- (2) A negative (cathodic) voltage shift of at least 300 millivolts. Determination of this voltage shift must be made with the protective current applied, and in accordance with Sections II and IV of this Appendix. This criterion of voltage shift applies to structures not in contact with metal of different anodic potentials.
- (3) A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with Sections III and IV of this Appendix.
- (4) A voltage at least as negative (cathodic) as that originally established at the beginning of the Tafel segment of the E-log-I curve. This voltage must be measured in accordance with Section IV of this appendix.
- (5) A net protective current from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.

B. *Aluminum structures*

- (1) Except as provided in Subparagraphs (3) and (4) of this paragraph, a minimum negative (cathodic) voltage shift of 150 millivolts, produced by the application of protective current. The voltage shift must be determined in accordance with Sections II and IV of this Appendix.
- (2) Except as provided in Subparagraphs (3) and (4) of this paragraph, a minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with Sections III and IV of this Appendix.
- (3) Notwithstanding the alternative minimum criteria in Subparagraphs (1) and (2) of this paragraph, aluminum, if cathodically protected at voltages in excess of 1.20 volts as measured with reference to a copper-copper sulfate half-cell, in accordance with Section IV of this appendix, and compensated for the voltage (IR) drops other than those across the structure-electrolyte boundary, may suffer corrosion resulting from the buildup of alkali on the metal surface. A voltage in excess of 1.20 volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.
- (4) Since aluminum may suffer from corrosion under high pH conditions, and since application of cathodic protection tends to increase the pH at the metal surface, careful investigation or testing must be made before applying cathodic protection to stop pitting attack on aluminum structures in environments with a natural pH in excess of 8.

C. *Copper structures*

A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with Sections III and IV of this Appendix.

D. Metals of different anodic potentials

A negative (cathodic) voltage, measured in accordance with Section IV of this appendix, equal to that required for the most anodic metal in the system must be maintained. If amphoteric structures are involved that could be damaged by high alkalinity covered by Subparagraphs (3) and (4) of paragraph B of this section, they must be electrically isolated with insulating flanges, or the equivalent.

II. Interpretation of Voltage Measurement

Voltage (IR) drops other than those across the structure-electrolyte boundary must be considered for valid interpretation of the voltage measurement in paragraphs A(1) and (2) and paragraph B(1) of Section I of this appendix.

III. Determination of Polarization Voltage Shift

The polarization voltage shift must be determined by interrupting the protective current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay in paragraphs A(3), B(2), and C of Section I of this appendix.

IV. Reference Half Cells

- A. Except as provided in paragraphs B and C of this section, negative (cathodic) voltage must be measured between the structure surface and a saturated copper-copper sulfate half cell contacting the electrolyte.
- B. Other standard reference half cells may be substituted for the saturated copper-copper sulfate half-cell. Two commonly used reference half cells are listed below along with their voltage equivalent to -0.85 volt as referred to a saturated copper-copper sulfate half cell:
 - (1) Saturated KCl calomel half cell: -0.78 volt.
 - (2) Silver-silver chloride half-cell used in sea water: -0.80 volt.
- C. In addition to the standard reference half cells, an alternate metallic material or structure may be used in place of the saturated copper sulfate half-cell if its potential stability is assured and if its voltage equivalent referred to a saturated copper-copper sulfate half-cell is established.

APPENDIX E TO PART 192 - GUIDANCE ON DETERMINING HIGH CONSEQUENCE AREAS AND ON CARRYING OUT REQUIREMENTS IN THE INTEGRITY MANAGEMENT RULE

I. Guidance on Determining a High Consequence Area

To determine which segments of an operator's transmission pipeline system are covered for purposes of the integrity management program requirements, an operator must identify the high consequence areas. An operator must use method (1) or (2) from the definition in § 192.903 to identify a high consequence area. An operator may apply one method to its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system. (Refer to figure E.1.A for a diagram of a high consequence area).

Determining High Consequence Area

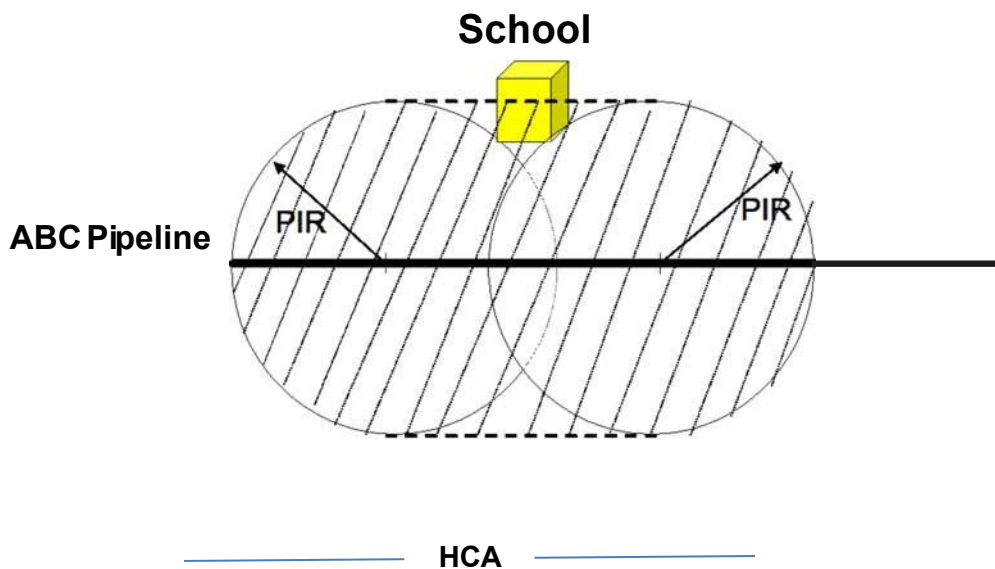


Figure E.1.A

II. Guidance on Assessment Methods and Additional Preventive and Mitigative Measures for Transmission Pipelines

- (a) Table E.11.1 gives guidance to help an operator implement requirements on additional preventive and mitigative measures for addressing time dependent and independent threats for a transmission pipeline operating below 30% SMYS not in an HCA (i.e. outside of potential impact circle) but located within a Class 3 or Class 4 Location.
- (b) Table E.11.2 gives guidance to help an operator implement requirements on assessment methods for addressing time dependent and independent threats for a transmission pipeline in an HCA.
- (c) Table E.11.3 gives guidance on preventative & mitigative measures addressing time dependent and independent threats for transmission pipelines that operate below 30% SMYS, in HCAs.

Table E.II.1

Preventive and Mitigative Measures for Transmission Pipelines Operating Below 30% SMYS not in an HCA but in a Class 3 or Class 4 Location

(Column 1) Threat	Existing 192 Requirements		(Column 4) Additional (to 192 requirements) Preventive and Mitigative
External Corrosion.....	455-(Gen. Post 1971), 457-(Gen. Pre-1971). 459-(Examination), 461-(Ext. coating). 463-(CP), 465-(Monitoring). 467-(Elect isolation), (469-Test stations). 471-(Test leads), 473-(Interference). 479-(Atmospheric), 481-(Atmospheric). 485-(Remedial), 705-(Patrol). 706-(Leak survey), 711 -(Repair-gen.) 717-(Repair-perm.)	603 – (Gen Operation)..... 613 - (Surveillance).....	<ul style="list-style-type: none"> • For Cathodically Protected Transmission Pipeline: • Perform semi-annual leak surveys. • For Unprotected Transmission Pipelines or for Cathodically Protected Pipe where Electrical Surveys are Impractical: • Perform quarterly leak surveys
Internal Corrosion	475-(Gen IC), 477-(IC monitoring). 485-(Remedial), 705-(Patrol). 706-(Leak survey), 711-(Repair-gen.). 717-(Repair - perm.).	53(a)-(Materials). 603-(Gen. Oper'n). 613-(Surveillance).	<ul style="list-style-type: none"> • Perform quarterly leak surveys. Perform semi-annual leak surveys.

<p>3rd Party Damage</p>	<p>103-(Gen. Design), 111-(Design factor). 317-(Hazard prot), 327-(Cover). 614-(Dam. Prevent), 616-(Public education). 705-(Patrol), 707-(Line markers). 711 (Repair-gen.), 717-(Repair-perm.).</p>	<p>615 (Emerg. Plan)</p>	<ul style="list-style-type: none"> •Participation in state one-call system, •Use of qualified operator employees and contractors to perform marking and locating of buried structures and in direct supervision of excavation work, AND •Either monitoring of excavations near operator's transmission pipelines, or bi-monthly patrol of transmission pipelines in class 3 and 4 locations. Any indications of unreported construction activity would require a follow up investigation to determine if mechanical damage occurred.
------------------------------------	---	--------------------------	---

Table E.II.2

**Assessment Requirements for Transmission Pipelines in HCAs
(Re-assessment intervals are maximum allowed)**

[table on next page]

	Re-Assessment Requirements (see Note 3)							
	At or above 50% SMYS		At or above 30% SMYS		Below 30% SMYS			
Baseline Assessment Method (see Note 3)	Max Re-Assessment Interval	Assessment Method	Max Re-Assessment Interval	Assessment Method	Max Re-Assessment Interval	Assessment Method		
Pressure Testing	7	CDA	7	CDA	Ongoing	Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)		
	10	Pressure Test or ILI or DA						
		Repeat inspection cycle every 10 years	15 (see Note 1)	Pressure Test or ILI or DA (see Note 1)				
				Repeat inspection cycle every 15 years			20	Pressure Test or ILI or DA
								Repeat inspection cycle every 20 years
In-Line Inspection	7	CDA	7	CDA	Ongoing	Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)		
	10	ILI or DA or Pressure Test						
		Repeat inspection cycle every 10 years	15 (see Note 1)	ILI or DA or Pressure Test (see Note 1)				
				Repeat inspection cycle every 15 years			20	ILI or DA or Pressure Test
								Repeat inspection cycle every 20 years
Direct Assessment	7	CDA	7	CDA	Ongoing	Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)		
	10	DA or ILI or Pressure Test						
		Repeat inspection cycle every 10 years	15 (see Note 1)	DA or ILI or Pressure Test (see Note 1)				
				Repeat inspection cycle every 15 years			20	DA or ILI or Pressure Test
								Repeat inspection cycle every 20 years

Note 1: Operator may choose to utilize CDA at year 14, then utilize ILI, Pressure Test, or DA at year 15 as allowed under ASME B31.8S.

Note 2: Operator may choose to utilize CDA at year 7 and 14 in lieu of P&M.

Note 3: Operator may utilize "other technology that an operator demonstrates can provide an equivalent understanding of the condition of line pipe."

**Table E.II.3
Preventative & Mitigative Measures addressing Time Dependent and Independent Threats for
Transmission Pipelines that Operate Below 30% SMYS, in HCAs**

Threat	Existing 192 Requirements		Additional (to 192 requirements) Preventive & Mitigative Measures
	Primary	Secondary	
External Corrosion	455 – (Gen. Post 1971) 457 – (Gen. pre1971) 459 - (Examination) 461 – (Ext. coating) 463 - (CP) 465 - (Monitoring) 467 – (Elect isolation)	603 - (Gen Oper) 613 - (Surveil)	<p><u>For Cathodically protected Trmn. Pipelines</u></p> <ul style="list-style-type: none"> •Perform an electrical survey (i.e. indirect examination tool/method) at least every 7 years. Results are to be utilized as part of an overall evaluation of the CP system and corrosion threat for the covered segment. Evaluation shall include consideration of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
External Corrosion	469 – (Test stations) 471 - (Test leads) 473 - (Interference) 479 - (Atmospheric) 481 – (Atmospheric) 485 - (Remedial) 705 - (Patrol) 706 - (Leak survey) 711 - (repair - gen.) 717 - (Repair perm.)		<p><u>For Unprotected Trmn. Pipelines or for Cathodically protected Pipe where Electrical Surveys are Impracticable</u></p> <ul style="list-style-type: none"> •Conduct quarterly leak surveys AND •Every 1 1/2 years, determine areas of active corrosion by evaluation of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
Internal Corrosion	475 - (Gen IC) 477 - (IC monitoring) 485 - (Remedial) 705 - (Patrol) 706 – (Leak survey) 711 – (repair - gen.) 717 - (Repair perm.)	53 (a) - (Materials) 603 - (Gen Oper) 613 - (Surveil)	<ul style="list-style-type: none"> •Obtain and review gas analysis data each calendar year for corrosive agents from transmission pipelines in HCAs, •Periodic testing of fluid removed from pipelines. Specifically, once each calendar year from each storage field that may affect transmission pipelines in HCAs, AND •At least every 7 years, integrate data obtained with applicable internal corrosion leak records, incident reports, safety related condition reports, repair records, patrol records, exposed pipe reports, and test records.

<p>3rd Party Damage</p>	<p>103 - (Gen. Design) 111 - (Design factor) 317 - (Hazard prot) 327 - (cover) 614 - (Dam. Prevent) 616 - (Public educat) 705 - (Patrol) 707 - (Line markers) 711 - (repair - gen.) 717 - (Repair-perm.)</p>	<p>615 - (Emerg Plan)</p>	<ul style="list-style-type: none"> •Participation in state one-call system, •Use of qualified operator employees and contractors to perform making and locating of buried structures and in direct supervision of excavation work, AND •Either monitoring of excavations near operator's transmission pipelines, or bi-monthly patrol of transmission pipelines in HCAs or class 3 or 4 locations. Any indications of unreported construction activity would require a follow up investigation to determine if mechanical damage occurred.
-----------------------------	--	-------------------------------	---

APPENDIX F TO PART 192 - CRITERIA FOR CONDUCTING INTEGRITY ASSESSMENTS USING GUIDED WAVE ULTRASONIC TESTING (GWUT)

This appendix defines criteria which must be properly implemented for use of guided wave ultrasonic testing (GWUT) as an integrity assessment method. Any application of GWUT that does not conform to these criteria is considered “other technology” as described by §§ 192.710(c)(7), 192.921(a)(7), and 192.937(c)(7), for which OPS must be notified 90 days prior to use in accordance with §§ 192.921(a)(7) or 192.937(c)(7). GWUT in the “Go–No Go” mode means that all indications (wall loss anomalies) above the testing threshold (a maximum of 5% of cross-sectional area (CSA) sensitivity) be directly examined, in-line tool inspected, pressure tested, or replaced prior to completing the integrity assessment on the carrier pipe.

- I. *Equipment and Software: Generation.* The equipment and the computer software used are critical to the success of the inspection. Computer software for the inspection equipment must be reviewed and updated, as required, on an annual basis, with intervals not to exceed 15 months, to support sensors, enhance functionality, and resolve any technical or operational issues identified.
- II. *Inspection Range.* The inspection range and sensitivity are set by the signal to noise (S/N) ratio but must still keep the maximum threshold sensitivity at 5% cross sectional area (CSA). A signal that has an amplitude that is at least twice the noise level can be reliably interpreted. The greater the S/N ratio the easier it is to identify and interpret signals from small changes. The signal to noise ratio is dependent on several variables such as surface roughness, coating, coating condition, associated pipe fittings (T's, elbows, flanges), soil compaction, and environment. Each of these affects the propagation of sound waves and influences the range of the test. It may be necessary to inspect from both ends of the pipeline segment to achieve a full inspection. In general, the inspection range can approach 60 to 100 feet for a 5% CSA, depending on field conditions.
- III. *Complete Pipe Inspection.* To ensure that the entire pipeline segment is assessed there should be at least a 2 to 1 signal to noise ratio across the entire pipeline segment that is inspected. This may require multiple GWUT shots. Double-ended inspections are expected. These two inspections are to be overlaid to show the minimum 2 to 1 S/N ratio is met in the middle. If possible, show the same near or midpoint feature from both sides and show an approximate 5% distance overlap.
- IV. *Sensitivity.* The detection sensitivity threshold determines the ability to identify a cross-sectional change. The maximum threshold sensitivity cannot be greater than 5% of the cross-sectional area (CSA).

The locations and estimated CSA of all metal loss features in excess of the detection threshold must be determined and documented.

All defect indications in the “Go-No-Go” mode above the 5% testing threshold must be directly examined, in-line inspected, pressure tested, or replaced prior to completing the integrity assessment.

- V. *Wave Frequency.* Because a single wave frequency may not detect certain defects, a minimum of three frequencies must be run for each inspection to determine the best frequency for characterizing indications. The frequencies used for the inspections must be documented and must be in the range specified by the manufacturer of the equipment.

- VI. *Signal or Wave Type: Torsional and Longitudinal.* Both torsional and longitudinal waves must be used, and use must be documented.
- VII. *Distance Amplitude Correction (DAC) Curve and Weld Calibration.* The distance amplitude correction curve accounts for coating, pipe diameter, pipe wall and environmental conditions at the assessment location. The DAC curve must be set for each inspection as part of establishing the effective range of a GWUT inspection. DAC curves provide a means for evaluating the cross-sectional area change of reflections at various distances in the test range by assessing signal to noise ratio. A DAC curve is a means of taking apparent attenuation into account along the time base of a test signal. It is a line of equal sensitivity along the trace which allows the amplitudes of signals at different axial distances from the collar to be compared.
- VIII. *Dead Zone.* The dead zone is the area adjacent to the collar in which the transmitted signal blinds the received signal, making it impossible to obtain reliable results. Because the entire line must be inspected, inspection procedures must account for the dead zone by requiring the movement of the collar for additional inspections. An alternate method of obtaining valid readings in the dead zone is to use B- scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.
- IX. *Near Field Effects.* The near field is the region beyond the dead zone where the receiving amplifiers are increasing in power, before the wave is properly established. Because the entire line must be inspected, inspection procedures must account for the near field by requiring the movement of the collar for additional inspections. An alternate method of obtaining valid readings in the near field is to use B- scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.
- X. *Coating Type.* Coatings can have the effect of attenuating the signal. Their thickness and condition are the primary factors that affect the rate of signal attenuation. Due to their variability, coatings make it difficult to predict the effective inspection distance. Several coating types may affect the GWUT results to the point that they may reduce the expected inspection distance. For example, concrete coated pipe may be problematic when well bonded due to the attenuation effects. If an inspection is done and the required sensitivity is not achieved for the entire length of the pipe, then another type of assessment method must be utilized.
- XI. *End Seal.* When assessing cased carrier pipe with GWUT, operators must remove the end seal from the casing at each GWUT test location to facilitate visual inspection. Operators must remove debris and water from the casing at the end seals. Any corrosion material observed must be removed, collected and reviewed by the operator's corrosion technician. The end seal does not interfere with the accuracy of the GWUT inspection but may have a dampening effect on the range.
- XII. *Weld Calibration to set DAC Curve.* Accessible welds, along or outside the pipeline segment to be inspected, must be used to set the DAC curve. A weld or welds in the access hole (secondary area) may be used if welds along the pipeline segment are not accessible. In order to use these welds in the secondary area, sufficient distance must be allowed to account for the dead zone and near field. There must not be a weld between the transducer collar and the calibration weld. A conservative estimate of the predicted amplitude for the weld is 25% CSA (cross sectional area) and can be used if welds are not accessible. Calibrations (setting of the DAC curve) should be on pipe with similar properties such as wall thickness and coating. If the actual weld cap height is different from the assumed weld cap height, the estimated CSA may be inaccurate and adjustments to the DAC curve may be required. Alternative means of calibration can be used if justified by a documented engineering analysis and evaluation.

XIII. *Validation of Operator Training.* Pipeline operators must require all guided wave service providers to have equipment-specific training and experience for all GWUT Equipment Operators which includes training for:

- Equipment operation,
- field data collection, and
- data interpretation on cased and buried pipe.

Only individuals who have been qualified by the manufacturer or an independently assessed evaluation procedure similar to ISO 9712 (Sections: 5 Responsibilities; 6 Levels of Qualification; 7 Eligibility; and 10 Certification), as specified above, may operate the equipment. A senior-level GWUT equipment operator with pipeline specific experience must provide onsite oversight of the inspection and approve the final reports. A senior-level GWUT equipment operator must have additional training and experience, including training specific to cased and buried pipe, with a quality control program which that conforms to Section 12 of ASME B31.8S (for availability, see § 192.7).

XIV. Training and Experience Minimums for Senior Level GWUT Equipment Operators:

- Equipment Manufacturer's minimum qualification for equipment operation and data collection with specific endorsements for casings and buried pipe
- Training, qualification and experience in testing procedures and frequency determination
- Training, qualification and experience in conversion of guided wave data into pipe features and estimated metal loss (estimated cross-sectional area loss and circumferential extent)
- Equipment Manufacturer's minimum qualification with specific endorsements for data interpretation of anomaly features for pipe within casings and buried pipe.

XV. *Equipment: Traceable from vendor to inspection company.* An operator must maintain documentation of the version of the GWUT software used and the serial number of the other equipment such as collars, cables, etc., in the report.

XVI. *Calibration Onsite.* The GWUT equipment must be calibrated for performance in accordance with the manufacturer's requirements and specifications, including the frequency of calibrations. A diagnostic check and system check must be performed on-site each time the equipment is relocated to a different casing or pipeline segment. If on-site diagnostics show a discrepancy with the manufacturer's requirements and specifications, testing must cease until the equipment can be restored to manufacturer's specifications.

XVII. *Use on Shorted Casings (direct or electrolytic).* GWUT may not be used to assess shorted casings. GWUT operators must have operations and maintenance procedures (see § 192.605) to address the effect of shorted casings on the GWUT signal. The equipment operator must clear any evidence of interference, other than some slight dampening of the GWUT signal from the shorted casing, according to their operating and maintenance procedures. All shorted casings found while conducting GWUT inspections must be addressed by the operator's standard operating procedures.

XVIII. *Direct examination of all indications above the detection sensitivity threshold.* The use of GWUT in the "Go-No Go" mode requires that all indications (wall loss anomalies) above the testing threshold (5% of CSA sensitivity) be directly examined (or replaced) prior to completing the

integrity assessment on the cased carrier pipe or other GWUT application. If this cannot be accomplished, then alternative methods of assessment (such as hydrostatic pressure tests or ILI) must be utilized.

- XIX. *Timing of direct examination of all indications above the detection sensitivity threshold.* Operators must either replace or conduct direct examinations of all indications identified above the detection sensitivity threshold according to the table below. Operators must conduct leak surveys and reduce operating pressure as specified until the pipe is replaced or direct examinations are completed.

Required Response to GWUT Indications			
GWUT criterion	Operating pressure less than or equal to 30% SMYS	Operating pressure over 30 and less than or equal to 50 SMYS	Operating pressure over 50% SMYS
Over the detection sensitivity threshold (maximum of 5% CSA)	Replace or direct examination within 12 months, and instrumented leak survey once every 30 calendar days	Replace or direct examination within 6 months, instrumented leak survey once every 30 calendar days, and maintain MAOP below the operating pressure at time of discovery	Replace or direct examination within 6 months, instrumented leak survey once every 30 calendar days, and reduce MAOP to 80% of operating pressure at time of discovery.

PART 199 - DRUG AND ALCOHOL TESTING

SUBPART A - GENERAL

§ 199.1 Scope

- (a) This part requires operators of pipeline facilities subject to part 192, 193, or 195 of this chapter to test covered employees for the presence of prohibited drugs and alcohol.

§ 199.2 Applicability

- (a) This part applies to pipeline operators only with respect to employees located within the territory of the United States, including those employees located within the limits of the "Outer Continental Shelf" as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).
- (b) This part does not apply to any person for whom compliance with this part would violate the domestic laws or policies of another country.
- (c) This part does not apply to covered functions performed on
 - (1) Master meter systems, as defined in § 191.3 of this chapter; or
 - (2) Pipeline systems that transport only petroleum gas or petroleum gas/air mixtures.

§ 199.3 Definitions

As used in this part—

Accident means an incident reportable under Part 191 involving gas pipeline facilities or LNG facilities.

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

Covered employee, employee, or individual to be tested means a person who performs a covered function, including persons employed by operators, contractors engaged by operators, and persons employed by such contractors.

Covered function means an operations, maintenance, or emergency-response function regulated by part 192, 193, or 195 of this chapter that is performed on a pipeline.

DOT Procedures means the Procedures for Transportation Workplace Drug and Alcohol Testing Programs published by the Office of the Secretary of Transportation in part 40 of this title.

Fail a drug test means that the confirmation test result shows positive evidence of the presence under DOT Procedures of a prohibited drug in an employee's system.

Operator means a person who owns or operates pipeline facilities subject to Part 192 or Part 193 of this Code.

Pass a drug test means that initial testing or confirmation testing under DOT Procedures does not show evidence of the presence of a prohibited drug in a person's system.

Performs a covered function includes actually performing, ready to perform, or immediately available to perform a covered function.

Positive rate for random drug testing means the number of verified positive results for random drug tests conducted under this part plus the number of refusals of random drug tests required by this part, divided by the total number of random drug tests results (i.e., positives, negatives,

and refusals) under this part.

Prohibited drug means any of the substances specified in 49 CFR part 40.

Refuse to submit, refuse, or refuse to take means behavior consistent with DOT Procedures concerning refusal to take a drug test or refusal to take an alcohol test.

State agency means an agency of any of the several states, the District of Columbia, or Puerto Rico that participates under the pipeline safety laws (49 U.S.C. 60101 *et seq.*).

§ 199.5 DOT Procedures

The anti-drug and alcohol programs required by this part must be conducted according to the requirements of this part and DOT Procedures. Terms and concepts used in this part have the same meaning as in DOT Procedures. Violations of DOT Procedures with respect to anti-drug and alcohol programs required by this part are violations of this part.

§ 199.7 Stand-down Waivers

- (a) Each operator who seeks a waiver under § 40.21 of this title from the stand-down restriction must submit an application for waiver in duplicate to the Associate Administrator for Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, 1200 New Jersey Avenue, SE, Washington, DC 20590-0001.
- (b) Each application must -
 - (1) Identify §40.21 of this title as the rule from which the waiver is sought;
 - (2) Explain why the waiver is requested and describe the employees to be covered by the waiver;
 - (3) Contain the information required by § 40.21 of this title and any other information or arguments available to support the waiver requested; and
 - (4) Unless good cause is shown in the application, be submitted at least 60 days before the proposed effective date of the waiver.
- (c) No public hearing or other proceeding is held directly on an application before its disposition under this section. If the Associate Administrator determines that the application contains adequate justification, he or she grants the waiver. If the Associate Administrator determines that the application does not justify granting the waiver, he or she denies the application. The Associate Administrator notifies each applicant of the decision to grant or deny an application.

§ 199.9 Preemption of State and Local Laws

- (a) Except as provided in paragraph (b) of this section, this subpart preempts any State or local law, rule, regulation, or order to the extent that:
 - (1) Compliance with both the State or local requirement and this subpart is not possible;
 - (2) Compliance with the State or local requirement is an obstacle to the accomplishment and execution of any requirement in this subpart; or
 - (3) The State or local requirement is a pipeline safety standard applicable to interstate pipeline facilities.
- (b) This subpart shall not be construed to preempt provisions of State criminal law that impose sanctions for reckless conduct leading to actual loss of life, injury, or damage to property, whether the provisions apply specifically to transportation employees or employers or to

the general public.

SUBPART B - DRUG TESTING

§ 199.100 Purpose

The purpose of this subpart is to establish programs designed to help prevent accidents and injuries resulting from the use of prohibited drugs by employees who perform covered functions for operators of certain pipeline facilities subject to part 192 or 195 of this chapter.

§ 199.101 Anti-Drug Plan

- (a) Each operator shall maintain and follow a written anti-drug plan that conforms to the requirements of this subpart and the DOT Procedures. The plan must contain:
 - (1) Methods and procedures for compliance with all the requirements of this subpart, including the employee assistance program;
 - (2) The name and address of each laboratory that analyzes the specimens collected for drug testing;
 - (3) The name and address of the operator's Medical Review Officer, and Substance Abuse Professional; and
 - (4) Procedures for notifying employees of the coverage and provisions of the plan.
- (b) The Administrator or the State Agency that has submitted a current certification under the pipeline safety law (49 U.S.C. 60101 *et seq.*) with respect to the pipeline facility governed by an operator's plans and procedures may, after notice and opportunity for hearing as provided in 49 CFR 190.206 or the relevant State procedures, require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety.

§ 199.103 Use of Persons Who Fail or Refuse a Drug Test

- (a) An operator may not knowingly use as an employee any person who:
 - (1) Fails a drug test required by this subpart and the medical review officer makes a determination under DOT Procedures; or
 - (2) Refuses to take a drug test required by this subpart.
- (b) Paragraph (a)(1) of this section does not apply to a person who has:
 - (1) Passed a drug test under DOT Procedures;
 - (2) Been considered by the medical review officer in accordance with DOT Procedures and been determined by a substance abuse professional to have successfully completed required education or treatment; and
 - (3) Not failed a drug test required by this subpart after returning to duty.

§ 199.105 Drug Tests Required

Each operator shall conduct the following drug tests for the presence of a prohibited drug:

- (a) Pre-employment testing. No operator may hire or contract for the use of any person as an employee unless that person passes a drug test or is covered by an anti-drug program that conforms to the requirements of this subpart.

(b) *Post-accident testing.*

- (1) As soon as possible but no later than 32 hours after an accident, an operator must drug test each surviving covered employee whose performance of a covered function either contributed to the accident or cannot be completely discounted as a contributing factor to the accident. An operator may decide not to test under this paragraph, but such a decision must be based on specific information that the covered employee's performance had no role in the cause(s) or severity of the accident.
- (2) If a test required by this section is not administered within the 32 hours following the accident, the operator must prepare and maintain its decision stating the reasons why the test was not promptly administered. If a test required by paragraph (b)(1) of this section is not administered within 32 hours following the accident, the operator must cease attempts to administer a drug test and must state in the record the reasons for not administering the test.

(c) *Random testing.*

- (1) Except as provided in paragraphs (c)(2) through (4) of this section, the minimum annual percentage rate for random drug testing shall be 50 percent of covered employees.
- (2) The Administrator's decision to increase or decrease the minimum annual percentage rate for random drug testing is based on the reported positive rate for the entire industry. All information used for this determination is drawn from the drug MIS reports required by this subpart. In order to ensure reliability of the data, the Administrator considers the quality and completeness of the reported data, may obtain additional information or reports from operators, and may make appropriate modifications in calculating the industry positive rate. Each year, the Administrator will publish in the Federal Register the minimum annual percentage rate for random drug testing of covered employees. The new minimum annual percentage rate for random drug testing will be applicable starting January 1 of the calendar year following publication.
- (3) When the minimum annual percentage rate for random drug testing is 50 percent, the Administrator may lower this rate to 25 percent of all covered employees if the Administrator determines that the data received under the reporting requirements of § 199.119 for two consecutive calendar years indicate that the reported positive rate is less than 1.0 percent.
- (4) When the minimum annual percentage rate for random drug testing is 25 percent, and the data received under the reporting requirements of § 199.119 for any calendar year indicate that the reported positive rate is equal to or greater than 1.0 percent, the Administrator will increase the minimum annual percentage rate for random drug testing to 50 percent of all covered employees.
- (5) The selection of employees for random drug testing shall be made by a scientifically valid method, such as a random number table or a computer-based random number generator that is matched with employees' Social Security numbers, payroll identification numbers, or other comparable identifying numbers. Under the selection process used, each covered employee shall have an equal chance of being tested each time selections are made.
- (6) The operator shall randomly select a sufficient number of covered employees for testing during each calendar year to equal an annual percentage rate not less than the minimum annual percentage rate for random drug testing determined by the

Administrator. If the operator conducts random drug testing through a consortium, the number of employees to be tested may be calculated for each individual operator or may be based on the total number of covered employees covered by the consortium who are subject to random drug testing at the same minimum annual percentage rate under this subpart or any DOT drug testing rule.

- (7) Each operator shall ensure that random drug tests conducted under this subpart are unannounced and that the dates for administering random tests are spread reasonably throughout the calendar year.
- (8) If a given covered employee is subject to random drug testing under the drug testing rules of more than one DOT agency for the same operator, the employee shall be subject to random drug testing at the percentage rate established for the calendar year by the DOT agency regulating more than 50 percent of the employee's function.
- (9) If an operator is required to conduct random drug testing under the drug testing rules of more than one DOT agency, the operator may-
 - (i) Establish separate pools for random selection, with each pool containing the covered employees who are subject to testing at the same required rate; or
 - (ii) Randomly select such employees for testing at the highest percentage rate established for the calendar year by any DOT agency to which the operator is subject.
- (d) Testing based on reasonable cause. Each operator shall drug test each employee when there is reasonable cause to believe the employee is using a prohibited drug. The decision to test must be based on a reasonable and articulable belief that the employee is using a prohibited drug on the basis of specific, contemporaneous physical, behavioral, or performance indicators of probable drug use. At least two of the employee's supervisors, one of whom is trained in detection of the possible symptoms of drug use, shall substantiate and concur in the decision to test an employee. The concurrence between the two supervisors may be by telephone. However, in the case of operators with 50 or fewer employees subject to testing under this subpart, only one supervisor of the employee trained in detecting possible drug use symptoms shall substantiate the decision to test.
- (e) Return-to-duty testing. A covered employee who refuses to take or has a positive drug test may not return to duty in the covered function until the covered employee has complied with applicable provisions of DOT Procedures concerning substance abuse professionals and the return-to-duty process.
- (f) Follow-up testing. A covered employee who refuses to take or has a positive drug test shall be subject to unannounced follow-up drug tests administered by the operator following the covered employee's the covered return to duty. The number and frequency of such follow-up testing shall be determined by a substance abuse professional but shall consist of at least six tests in the first 12 months following the covered employee's return to duty. In addition, follow-up testing may include testing for alcohol as directed by the substance abuse professional, to be performed in accordance with 49 CFR 40. Follow-up testing shall not exceed 60 months from the date of the covered employee's return to duty. The substance abuse professional may terminate the requirement for follow-up testing at any time after the first six tests have been administered, if the substances abuse professional determines that such testing is no longer necessary.

§ 199.107 Drug Testing Laboratory

- (a) Each operator shall use for the drug testing required by this subpart only drug testing laboratories certified by the Department of Health and Human Services under the DOT Procedures.
- (b) The drug testing laboratory must permit:
 - (1) Inspections by the operator before the laboratory is awarded a testing contract; and
 - (2) Unannounced inspections, including examination of records, at any time, by the operator, the Administrator, and if the operator is subject to state agency jurisdiction, a representative of that state agency.

§ 199.109 Review of Drug Testing Results

- (a) *MRO appointment.* Each operator shall designate or appoint a medical review officer (MRO). If an operator does not have a qualified individual on staff to serve as MRO, the operator may contract for the provision of MRO services as part of its anti-drug program.
- (b) *MRO qualifications.* Each MRO must be a licensed physician who has the qualifications required by DOT Procedures.
- (c) *MRO duties.* The MRO must perform functions for the operator as required by DOT Procedures.
- (d) *MRO reports.* The MRO must report all drug test results to the operator in accordance with DOT Procedures.
- (e) Evaluation and rehabilitation may be provided by the operator, by a substance abuse professional under contract with the operator, or by a substance abuse professional not affiliated with the operator. The choice of substance abuse professional and assignment of costs shall be made in accordance with the operator/employee policies.
- (f) The operator shall ensure that a substance abuse professional, who determines that a covered employee requires assistance in resolving problems with drug abuse, does not refer the covered employee to the substance abuse professional's private practice or to a person or organization from which the substance abuse professional receives remuneration or in which the substance abuse professional has a financial interest. This paragraph does not prohibit a substance abuse professional from referring a covered employee for assistance provided through:
 - (1) A public agency, such as a State, county, or municipality;
 - (2) The operator or a person under contract to provide treatment for drug problems on behalf of the operator;
 - (3) The sole source of therapeutically appropriate treatment under the employee's health insurance program; or
 - (4) The sole source of therapeutically appropriate treatment reasonably accessible to the employee.

§ 199.111 [Removed and Reserved]

§ 199.113 Employee Assistance Program

- (a) Each operator shall provide an employee assistance program (EAP) for its employees and supervisory personnel who will determine whether an employee must be drug tested based on reasonable cause. The operator may establish the EAP as a part of its internal personnel services, or the operator may contract with an entity that provides EAP services.

Each EAP must include education and training on drug use. At the discretion of the operator, the EAP may include an opportunity for employee rehabilitation.

- (b) Education under each EAP must include at least the following elements: display and distribution of informational material; display and distribution of a community service hot-line telephone number for employee assistance; and display and distribution of the employer's policy regarding the use of prohibited drugs.
- (c) Training under each EAP for supervisory personnel who will determine whether an employee must be drug tested based on reasonable cause must include one 60-minute period of training on the specific, contemporaneous physical, behavioral, and performance indicators of probable drug use.

§ 199.115 Contractor Employees

With respect to those employees who are contractors or employed by a contractor, an operator may provide by contract that the drug testing, education, and training required by this subpart be carried out by the contractor provided:

- (a) The operator remains responsible for ensuring that the requirements of this subpart are complied with; and
- (b) The contractor allows access to property and records by the operator, the Administrator, and if the operator is subject to the jurisdiction of a state agency, a representative of the state agency for the purpose of monitoring the operator's compliance with the requirements of this subpart.

§ 199.117 Record Keeping

- (a) Each operator shall keep the following records for the periods specified and permit access to the records as provided by paragraph (b) of this section:
 - (1) Records that demonstrate the collection process conforms to this subpart must be kept for at least 3 years.
 - (2) Records of employee drug test that indicate a verified positive result, records that demonstrate compliance with the recommendations of a substance abuse professional, and MIS annual report data shall be maintained for a minimum of five years.
 - (3) Records of employee drug test results that show employees passed a drug test must be kept for at least 1 year.
 - (4) Records confirming that supervisors and employees have been trained as required by this part must be kept for at least 3 years.
- (b) Information regarding an individual's drug testing results or rehabilitation must be released upon the written consent of the individual and as provided by DOT Procedures.

§ 199.119 Reporting of Anti-Drug Testing Results

- (a) Each large operator (having more than 50 covered employees) must submit an annual Management Information System (MIS) report to PHMSA of its anti-drug testing using the MIS form and instructions as required by 49 CFR part 40 (at § 40.26 and appendix H to part 40), not later than March 15 of each year for the prior calendar year (January 1 through December 31). The Administrator may require by notice in the PHMSA Portal (<https://portal.phmsa.dot.gov/phmsaportallanding>) that small operators (50 or fewer covered employees), not otherwise required to submit annual MIS reports, to prepare and submit such reports to PHMSA.
- (b) Each report required under this section must be submitted electronically at

<http://damis.dot.gov>. An operator may obtain the username and password needed for electronic reporting from the PHMSA Portal (<https://portal.phmsa.dot.gov/phmsaportallanding>). If electronic reporting imposes an undue burden and hardship, the operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE., Washington, DC 20590. PHMSA will review the request and may authorize, in writing, an alternative reporting method. The request must describe the undue burden and hardship. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202-366-8075, or electronically to informationresourcesmanager@dot.gov to make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received.

- (c) To calculate the total number of covered employees eligible for random testing throughout the year, as an operator, you must add the total number of covered employees eligible for testing during each random testing period for the year and divide that total by the number of random testing periods. Covered employees, and only covered employees, are to be in an employer's random testing pool, and all covered employees must be in the random pool. If you are an employer conducting random testing more often than once per month (e.g., you select daily, weekly, bi-weekly), you do not need to compute this total number of covered employees' rate more than on a once per month basis.
- (d) As an employer, you may use a service agent (e.g., C/TPA) to perform random selections for you; and your covered employees may be part of a larger random testing pool of covered employees. However, you must ensure that the service agent you use is testing at the appropriate percentage established for your industry and that only covered employees are in the random testing pool.
- (e) Each operator that has a covered employee who performs multi-DOT agency functions (e.g., an employee performs pipeline maintenance duties and drives a commercial motor vehicle), count the employee only on the MIS report for the DOT agency under which he or she is randomly tested. Normally, this will be the DOT agency under which the employee performs more than 50% of his or her duties. Operators may have to explain the testing data for these employees in the event of a DOT agency inspection or audit.
- (f) A service agent (e.g., Consortia/Third Party Administrator as defined in 49 CFR Part 40) may prepare the MIS report on behalf of an operator. However, each report shall be certified by the operator's anti-drug manager or designated representative for accuracy and completeness.

SUBPART C - ALCOHOL MISUSE PREVENTION PROGRAM

§ 199.200 Purpose

The purpose of this subpart is to establish programs designed to help prevent accidents and injuries resulting from the misuse of alcohol by employees who perform covered functions for operators of certain pipeline facilities subject to part 192 of this code.

§ 199.201 [Reserved]

§ 199.202 Alcohol Misuse Plan

Each operator must maintain and follow a written alcohol misuse plan that conforms to the requirements of this part and DOT Procedures concerning alcohol testing programs. The plan shall contain methods

and procedures for compliance with all the requirements of this subpart, including required testing, record keeping, reporting, education and training elements.

§§ 199.203-199.205 [Reserved]

§ 199.209 Other Requirements Imposed by Operators

- (a) Except as expressly provided in this subpart, nothing in this subpart shall be construed to affect the authority of operators, or the rights of employees, with respect to the use or possession of alcohol, including authority and rights with respect to alcohol testing and rehabilitation.
- (b) Operators may, but are not required to, conduct pre-employment alcohol testing under this subpart. Each operator that conducts pre-employment alcohol testing must-
 - (1) Conduct a pre-employment alcohol test before the first performance of covered functions by every covered employee (whether a new employee or someone who has transferred to a position involving the performance of covered functions);
 - (2) Treat all covered employees the same for the purpose of pre-employment alcohol testing (i.e., you must not test some covered employees and not others);
 - (3) Conduct the pre-employment tests after making a contingent offer of employment or transfer, subject to the employee passing the pre-employment alcohol test;
 - (4) Conduct all pre-employment alcohol tests using the alcohol testing procedures in DOT Procedures; and
 - (5) Not allow any covered employee to begin performing covered functions unless the result of the employee's test indicates an alcohol concentration of less than 0.04.

§ 199.211 Requirements for Notice

Before performing an alcohol test under this subpart, each operator shall notify a covered employee that the alcohol test is required by this subpart. No operator shall falsely represent that a test is administered under this subpart.

§ 199.213 [Reserved]

§ 199.215 Alcohol Concentration

Each operator shall prohibit a covered employee from reporting for duty or remaining on duty requiring the performance of covered functions while having an alcohol concentration of 0.04 or greater. No operator having actual knowledge that a covered employee has an alcohol concentration of 0.04 or greater shall permit the employee to perform or continue to perform covered functions.

§ 199.217 On-duty Use

Each operator shall prohibit a covered employee from using alcohol while performing covered functions. No operator having actual knowledge that a covered employee is using alcohol while performing covered functions shall permit the employee to perform or continue to perform covered functions.

§ 199.219 Pre-duty Use

Each operator shall prohibit a covered employee from using alcohol within four hours prior to performing covered functions, or, if an employee is called to duty to respond to an emergency, within the time period after the employee has been notified to report for duty. No operator having actual knowledge that a covered employee has used alcohol within four hours prior to performing covered functions or within the time period after the employee has been notified to report for duty shall permit that covered employee

to perform or continue to perform covered functions.

§ 199.221 Use Following an Accident

Each operator shall prohibit a covered employee who has actual knowledge of an accident in which his or her performance of covered functions has not been discounted by the operator as a contributing factor to the accident from using alcohol for eight hours following the accident, unless he or she has been given a post-accident test under § 199.225(a), or the operator has determined that the employee's performance could not have contributed to the accident.

§ 199.223 Refusal to Submit to a Required Alcohol Test

Each operator shall require a covered employee to submit to a post-accident alcohol test required under § 199.225(a), a reasonable suspicion alcohol test required under § 199.225(b), or a follow-up alcohol test required under § 199.225(d). No operator shall permit an employee who refuses to submit to such a test to perform or continue to perform covered functions.

§ 199.225 Alcohol Tests Required

Each operator shall conduct the following types of alcohol tests for the presence of alcohol:

- (a) Post-accident.
 - (1) As soon as practicable following an accident, each operator must test each surviving covered employee for alcohol if that employee's performance of a covered function either contributed to the accident or cannot be completely discounted as a contributing factor to the accident. The decision not to administer a test under this section must be based on specific information that the covered employee's performance had no role in the cause(s) or severity of the accident.
 - (2) (i) If a test required by this section is not administered within two hours following the accident, the operator shall prepare and maintain on file a record stating the reasons the test was not promptly administered. If a test required by paragraph (a) is not administered within eight hours following the accident, the operator shall cease attempts to administer an alcohol test and shall state in the record the reasons for not administering the test.
 - (i) [Removed and Reserved].
 - (2) A covered employee who is subject to post-accident testing who fails to remain readily available for such testing, including notifying the operator or operator representative of his/her location if he/she leaves the scene of the accident prior to submission to such test, may be deemed by the operator to have refused to submit to testing. Nothing in this section shall be construed to require the delay of necessary medical attention for injured people following an accident or to prohibit a covered employee from leaving the scene of an accident for the period necessary to obtain assistance in responding to the accident or to obtain necessary emergency medical care.
- (b) *Reasonable suspicion testing.*
 - (1) Each operator shall require a covered employee to submit to an alcohol test when the operator has reasonable suspicion to believe that the employee has violated the prohibitions in this subpart.
 - (2) The operator's determination that reasonable suspicion exists to require the covered employee to undergo an alcohol test shall be based on specific, contemporaneous, articulable observations concerning the appearance, behavior,

speech, or body odors of the employee. The required observations shall be made by a supervisor who is trained in detecting the symptoms of alcohol misuse. The supervisor who makes the determination that reasonable suspicion exists shall not conduct the breath alcohol test on that employee.

- (3) Alcohol testing is authorized by this section only if the observations required by subparagraph (b)(2) of this paragraph are made during, just preceding, or just after the period of the workday that the employee is required to be in compliance with this subpart. A covered employee may be directed by the operator to undergo reasonable suspicion testing for alcohol only while the employee is performing covered functions; just before the employee is to perform covered functions; or just after the employee has ceased performing covered functions.
- (4)
 - (i) If a test required by this paragraph is not administered within two hours following the determination under subparagraph (b)(2) of this paragraph, the operator shall prepare and maintain on file a record stating the reasons the test was not promptly administered. If a test required by this paragraph is not administered within eight hours following the determination under subparagraph (b)(2) of this paragraph, the operator shall cease attempts to administer an alcohol test and shall state in the record the reasons for not administering the test. Records shall be submitted to PHMSA upon request of the Administrator.
 - (ii) [Removed and Reserved].
 - (iii) Notwithstanding the absence of a reasonable suspicion alcohol test under this paragraph, an operator shall not permit a covered employee to report for duty or remain on duty requiring the performance of covered functions while the employee is under the influence of or impaired by alcohol, as shown by the behavioral, speech, or performance indicators of alcohol misuse, nor shall an operator permit the covered employee to perform or continue to perform covered functions, until:
 - (A) An alcohol test is administered and the employee's alcohol concentration measures less than 0.02; or
 - (B) The start of the employee's next regularly scheduled duty period, but not less than 8 hours following the determination under subparagraph (b)(2) of this paragraph that there is reasonable suspicion to believe that the employee has violated the prohibitions in this subpart.
 - (iv) Except as provided in subparagraph (b)(4)(ii), no operator shall take any action under this subpart against a covered employee based solely on the employee's behavior and appearance in the absence of an alcohol test. This does not prohibit an operator with the authority independent of this subpart from taking any action otherwise consistent with law.
- (c) *Return-to-duty testing.* Each operator shall ensure that before a covered employee returns to duty requiring the performance of a covered function after engaging in conduct prohibited by §§ 199.215 through 199.223, the employee shall undergo a return-to-duty alcohol test with a result indicating an alcohol concentration of less than 0.02.
- (d) *Follow-up testing.*
 - (1) Following a determination under § 199.243(b) that a covered employee is in need of assistance in resolving problems associated with alcohol misuse, each operator shall ensure that the employee is subject to unannounced follow-up alcohol testing

as directed by a substance abuse professional in accordance with the provisions of § 199.243(c)(2)(ii).

- (2) Follow-up testing shall be conducted when the covered employee is performing covered functions; just before the employee is to perform covered functions; or just after the employee has ceased performing such functions.
- (e) *Retesting of covered employees with an alcohol concentration of 0.02 or greater but less than 0.04.* Each operator shall retest a covered employee to ensure compliance with the provisions of § 199.237, if an operator chooses to permit the employee to perform a covered function within eight hours following the administration of an alcohol test indicating an alcohol concentration of 0.02 or greater but less than 0.04.

§ 199.227 Retention of Records

- (a) General requirement. Each operator shall maintain records of its alcohol misuse prevention program as provided in this paragraph. The records shall be maintained in a secure location with controlled access.
- (b) Period of retention. Each operator shall maintain the records in accordance with the following schedule:
 - (1) Five years. Records of employee alcohol test results with results indicating an alcohol concentration of 0.02 or greater, documentation of refusals to take required alcohol tests, calibration documentation, employee evaluation and referrals, and MIS annual report data shall be maintained for a minimum of five years.
 - (2) Two years. Records related to the collection process (except calibration of evidential breath testing devices), and training shall be maintained for a minimum of two years.
 - (3) One year. Records of all test results below 0.02 (as defined in 49 CFR Part 40) shall be maintained for a minimum of one year.
 - (4) Three years. Records of decisions not to administer post-accident employee alcohol tests must be kept for a minimum of three years.
- (c) Types of records. The following specific records shall be maintained:
 - (1) Records related to the collection process:
 - (i) Collection logbooks, if used.
 - (ii) Calibration documentation for evidential breath testing devices.
 - (iii) Documentation of breath alcohol technician training.
 - (iv) Documents generated in connection with decisions to administer reasonable suspicion alcohol tests.
 - (v) Documents generated in connection with decisions on post-accident tests.
 - (vi) Documents verifying existence of a medical explanation of the inability of a covered employee to provide adequate breath for testing.
 - (2) Records related to test results:
 - (i) The operator's copy of the alcohol test form, including the results of the test.
 - (ii) Documents related to the refusal of any covered employee to submit to an alcohol test required by this subpart.

- (iii) Documents presented by a covered employee to dispute the result of an alcohol test administered under this subpart.
- (3) Records related to other violations of this subpart.
- (4) Records related to evaluations:
 - (i) Records pertaining to a determination by a substance abuse professional concerning a covered employee's need for assistance.
 - (ii) Records concerning a covered employee's compliance with the recommendations of the substance abuse professional.
- (5) Record(s) related to the operator's MIS annual testing data.
- (6) Records related to education and training:
 - (i) Materials on alcohol misuse awareness, including a copy of the operator's policy on alcohol misuse.
 - (ii) Documentation of compliance with the requirements of § 199.231.
 - (iii) Documentation of training provided to supervisors for the purpose of qualifying the supervisors to make a determination concerning the need for alcohol testing based on reasonable suspicion.
 - (iv) Certification that any training conducted under this subpart complies with the requirements for such training.

§ 199.229 Reporting of Alcohol Testing Results

- (a) Each large operator (having more than 50 covered employees) must submit an annual MIS report to PHMSA of its alcohol testing results using the MIS form and instructions as required by 49 CFR part 40 (at § 40.26 and appendix H to part 40) not later than March 15 of each year for the prior calendar year (January 1 through December 31). The Administrator may require by notice in the PHMSA Portal (<https://portal.phmsa.dot.gov/phmsaportallanding>) that small operators (50 or fewer covered employees), not otherwise required to submit annual MIS reports, to prepare and submit such reports to PHMSA.
- (b) Each operator that has a covered employee who performs multi-DOT agency functions (e.g., an employee performs pipeline maintenance duties and drives a commercial motor vehicle), count the employee only on the MIS report for the DOT agency under which he or she is tested. Normally, this will be the DOT agency under which the employee performs more than 50% of his or her duties. Operators may have to explain the testing data for these employees in the event of a DOT agency inspection or audit.
- (c) Each report required under this section must be submitted electronically at <http://damis.dot.gov>. An operator may obtain the user name and password needed for electronic reporting from the PHMSA Portal <https://portal.phmsa.dot.gov/phmsaportallanding>. If electronic reporting imposes an undue burden and hardship, the operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE., Washington, DC 20590. The request must describe the undue burden and hardship. PHMSA will review the request and authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202- 366-8075, or electronically to informationresourcesmanager@dot.gov to make arrangements for submitting a report that is due after a request for alternative

reporting is submitted but before an authorization or denial is received.

- (d) A service agent (e.g., Consortia/Third Party Administrator as defined in Part 40) may prepare the MIS report on behalf of an operator. However, each report shall be certified by the operator's anti-drug manager or designated representative for accuracy and completeness.

§ 199.231 Access to Facilities and Records

- (a) Except as required by law or expressly authorized or required in this subpart, no employer shall release covered employee information that is contained in records required to be maintained in § 199.227.
- (b) A covered employee is entitled, upon written request, to obtain copies of any records pertaining to the employee's use of alcohol, including any records pertaining to his or her alcohol tests. The operator shall promptly provide the records requested by the employee. Access to an employee's records shall not be contingent upon payment for records other than those specifically requested.
- (c) Each operator shall permit access to all facilities utilized in complying with the requirements of this subpart to the Secretary of Transportation, any DOT agency, or a representative of a state agency with regulatory authority over the operator.
- (d) Each operator shall make available copies of all results for employer alcohol testing conducted under this subpart and any other information pertaining to the operator's alcohol misuse prevention program, when requested by the Secretary of Transportation, any DOT agency with regulatory authority over the operator, or a representative of a state agency with regulatory authority over the operator. The information shall include name-specific alcohol test results, records, and reports.
- (e) When requested by the National Transportation Safety Board as part of an accident investigation, an operator shall disclose information related to the operator's administration of any post-accident alcohol tests administered following the accident under investigation.
- (f) An operator shall make records available to a subsequent employer upon receipt of the written request from the covered employee. Disclosure by the subsequent employer is permitted only as expressly authorized by the terms of the employee's written request.
- (g) An operator may disclose information without employee consent as provided by DOT Procedures concerning certain legal proceedings.
- (h) An operator shall release information regarding a covered employee's records as directed by the specific, written consent of the employee authorizing release of the information to an identified person. Release of such information by the person receiving the information is permitted only in accordance with the terms of the employee's consent.

§ 199.233 Removal from Covered Function

Except as provided in §§ 199.239 through 199.243, no operator shall permit any covered employee to perform covered functions if the employee has engaged in conduct prohibited by §§ 199.215 through 199.223 or an alcohol misuse rule of another DOT agency.

§ 199.235 Required Evaluation and Testing

No operator shall permit a covered employee who has engaged in conduct prohibited by §§ 199.215 through 199.223 to perform covered functions unless the employee has met the requirements of § 199.243.

§ 199.237 Other Alcohol-related Conduct

- (a) No operator shall permit a covered employee tested under the provisions of § 199.225, who is found to have an alcohol concentration of 0.02 or greater but less than 0.04, to perform or continue to perform covered functions, until:
 - (1) The employee's alcohol concentration measures less than 0.02 in accordance with a test administered under § 199.225(e); or
 - (2) The start of the employee's next regularly scheduled duty period, but not less than eight hours following administration of the test.
- (b) Except as provided in paragraph (a) of this section, no operator shall take any action under this subpart against an employee based solely on test results showing an alcohol concentration less than 0.04. This does not prohibit an operator with authority independent of this subpart from taking any action otherwise consistent with law.

§ 199.239 Operator Obligation to Promulgate a Policy on the Misuse of Alcohol

- (a) General requirement. Each operator shall provide educational materials that explain these alcohol misuse requirements and the operator's policies and procedures with respect to meeting those requirements.
 - (1) The operator shall ensure that a copy of these materials is distributed to each covered employee prior to the start of alcohol testing under this subpart, and to each person subsequently hired for or transferred to a covered position.
 - (2) Each operator shall provide written notice to representatives of employee organizations of the availability of this information.
- (b) Required content. The materials to be made available to covered employees shall include detailed discussion of at least the following:
 - (1) The identity of the person designated by the operator to answer covered employee's questions about the materials.
 - (2) The categories of employees who are subject to the provisions of this subpart.
 - (3) Sufficient information about the covered functions performed by those employees to make clear what period of the workday the covered employee is required to be in compliance with this subpart.
 - (4) Specific information concerning covered employee conduct that is prohibited by this subpart.
 - (5) The circumstances under which a covered employee will be tested for alcohol under this subpart.
 - (6) The procedures that will be used to test for the presence of alcohol, protect the covered employee and the integrity of the breath testing process, safeguard the validity of the test results, and ensure that those results are attributed to the correct employee.
 - (7) The requirement that a covered employee submit to alcohol tests administered in accordance with this subpart.
 - (8) An explanation of what constitutes a refusal to submit to an alcohol test and the attendant consequences.
 - (9) The consequences for covered employees found to have violated the prohibitions under this subpart, including the requirement that the employee be removed

immediately from covered functions, and the procedures under § 199.243.

- (10) The consequences for covered employees found to have an alcohol concentration of 0.02 or greater but less than 0.04.
 - (11) Information concerning the effects of alcohol misuse on an individual's health, work, and personal life; signs and symptoms of an alcohol problem (the employee's or a coworker's); and including intervening evaluating and resolving problems associated with the misuse of alcohol including intervening when an alcohol problem is suspected, confrontation, referral to any available EAP, and/or referral to management.
- (c) Optional provisions. The materials supplied to covered employees may also include information on additional operator policies with respect to the use or possession of alcohol, including any consequences for an employee found to have a specified alcohol level, that are based on the operator's authority independent of this subpart. Any such additional policies or consequences shall be clearly described as being based on independent authority.

§ 199.241 Training for Supervisors

Each operator shall ensure that persons designated to determine whether reasonable suspicion exists to require a covered employee to undergo alcohol testing under § 199.225(b) receive at least 60 minutes of training on the physical, behavioral, speech, and performance indicators of probable alcohol misuse.

§ 199.243 Referral, Evaluation, and Treatment

- (a) Each covered employee who has engaged in conduct prohibited by §§ 199.215 through 199.223 of this subpart shall be advised of the resources available to the covered employee in evaluating and resolving problems associated with the misuse of alcohol, including the names, addresses, and telephone numbers of substance abuse professionals and counseling and treatment programs.
- (b) Each covered employee who engages in conduct prohibited under §§ 199.215 through 199.223 shall be evaluated by a substance abuse professional who shall determine what assistance, if any, the employee needs in resolving problems associated with alcohol misuse.
- (c) (1) Before a covered employee returns to duty requiring the performance of a covered function after engaging in conduct prohibited by §§ 199.215 through 199.223 of this subpart, the employee shall undergo a return-to-duty alcohol test with a result indicating an alcohol concentration of less than 0.02.
(2) In addition, each covered employee identified as needing assistance in resolving problems associated with alcohol misuse:
 - (i) Shall be evaluated by a substance abuse professional to determine that the employee has properly followed any rehabilitation program prescribed under paragraph (b) of this section.
 - (ii) Shall be subject to unannounced follow-up alcohol tests administered by the operator following the employee's return to duty. The number and frequency of such follow-up testing shall be determined by a substance abuse professional but shall consist of at least six tests in the first 12 months following the employee's return to duty. In addition, follow-up testing may include testing for drugs, as directed by the substance abuse professional, to be performed in accordance with 49 CFR Part 40. Follow-up testing shall not exceed 60 months from the date of the employee's

return to duty. The substance abuse professional may terminate the requirement for follow-up testing at any time after the first six tests have been administered, if the substance abuse professional determines that such testing is no longer necessary.

- (d) Evaluation and rehabilitation may be provided by the operator, by a substance abuse professional under contract with the operator, or by a substance abuse professional not affiliated with the operator. The choice of substance abuse professional and assignment of costs shall be made in accordance with the operator/employee agreements and operator/employee policies.
- (e) The operator shall ensure that a substance abuse professional who determines that a covered employee requires assistance in resolving problems with alcohol misuse does not refer the employee to the substance abuse professional's private practice or to a person or organization from which the substance abuse professional receives remuneration or in which the substance abuse professional has a financial interest. This paragraph does not prohibit a substance abuse professional from referring an employee for assistance provided through:
 - (1) A public agency, such as a State, county, or municipality;
 - (2) The operator or a person under contract to provide treatment for alcohol problems on behalf of the operator;
 - (3) The sole source of therapeutically appropriate treatment under the employee's health insurance program; or
 - (4) The sole source of therapeutically appropriate treatment reasonably accessible to the employee.

§ 199.245 Contractor Employees

- (a) With respect to those covered employees who are contractors or employed by a contractor, an operator may provide by contract that the alcohol testing, training and education required by this subpart be carried out by the contractor provided:
- (b) The operator remains responsible for ensuring that the requirements of this subpart and 49 CFR Part 40 are complied with; and
- (c) The contractor allows access to property and records by the operator, the Administrator, any DOT agency with regulatory authority over the operator or covered employee, and if the operator is subject to the jurisdiction of a state agency, a representative of the state agency for the purposes of monitoring the operator's compliance with the requirements of this subpart and 49 CFR Part 40.