STANDARD INSPECTION REPORT OF A GAS DISTRIBUTION OPERATOR

A completed **Standard Inspection Report** is to be submitted to the Director within 60 days from completion of the inspection. A **Post Inspection Memorandum (PIM)** is to be completed and submitted to the Director within 30 days from the completion of the inspection, or series of inspections, and is to be filed as part of the **Standard Inspection Report.**

Inspection Report		**Post Inspection Memorandum**	
Inspector/Submit Date:		**Inspector/Submit Date:**	
		Peer Review/Date:	
		Director Approval/Date:	

POST INSPECTION MEMORANDUM (PIM)			
Name of Operator:		**OPID #:**	
Name of Unit(s):		**Unit #(s):**	
Records Location:		**Activity #**	
Unit Type & Commodity:			
Inspection Type:		**Inspection Date(s):**	
PHMSA Representative(s):		**AFO Days:**	

Company System Maps (copies for Region Files):	
Validate SMART Data (components, miles, etc): ☐	**Acquisition(s), Sale or New Construction** (submit SMART update): ☐
Validate Additional Requirements Resulting From Waiver(s) or Special Permit(s):	

Summary:

Findings:

STANDARD INSPECTION REPORT OF A GAS DISTRIBUTION OPERATOR

Name of Operator:			
OP ID No. [1]		**Unit ID No.** [1]	
HQ Address:		**System/Unit Name & Address:** [1]	
Co. Official:		**Activity Record ID No.:**	
Phone No.:		**Phone No.:**	
Fax No.:		**Fax No.:**	
Emergency Phone No.:		**Emergency Phone No.:**	

Persons Interviewed	**Title**	**Phone No.**

PHMSA Representative(s) [1]		**Inspection Date(s)** [1]	
Company System Maps (Copies for Region Files):			

Unit Description

Portion of Unit Inspected: [1]

For gas transmission and distribution pipeline inspections, the attached evaluation form should be used in conjunction with 49CFR Parts 191 and 192.

[1] Information not required if included on page 1.

STANDARD INSPECTION REPORT OF A GAS DISTRIBUTION OPERATOR

Unless otherwise noted, all code references are to 49CFR Part 192. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked

If an item is marked U, N/A, or N/C, an explanation must be included in this report.

GAS SYSTEM OPERATIONS						
Gas Supplier		**Date:**				
Unaccounted for gas:		**Services:**	***Residential***	***Commercial***	***Industrial***	***Other***

Operating Pressure(s):		**MAOP (Within last year)**	**Actual Operating Pressure** (At time of Inspection)
Feeder:			
Town:			
Other:			
Does the operator have any transmission pipelines?			
For compressor station inspections, use Attachment 4.			

49CFR PART 191

	REPORTING PROCEDURES	**S**	**U**	**N/A**	**N/C**
.605(b)(4)	Procedures for gathering data for incident reporting				
	191.5 Immediate Notice of certain incidents to **NRC (800) 424-8802,** or electronically at http://www.nrc.uscg.mil/nrchp.html. *(191.3 - A release of gas from a pipeline, that results in a death or personal injury necessitating in-patient hospitalization, estimated property damage of $50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost, unintentional estimated gas loss of three million cubic feet or more, or an event that is significant in the judgment of the operator.)*				
	191.7 Reports (except SRCR and offshore pipeline condition reports) must be submitted electronically to PHMSA at https://opsweb.phmsa.dot.gov unless an alternative reporting method is authorized IAW with paragraph (d) of this section.				
	191.15(a) 30-day follow-up written report (**Form 7100-2**) Submittal must be electronically to http://pipelineonlinereporting.phmsa.dot.gov				
	191.15(c) Supplemental report (to 30-day follow-up)				
.605(a)	191.17 Complete and submit DOT Form PHMSA F 7100-2.1 by March 15 of each calendar year for the preceding year. *(NOTE: June 15, 2011 [may change to August 15] for the year 2010).*				
	191.22 Each operator must obtain an OPID, validate its OPIDs, and notify PHMSA of certain events at https://opsweb.phmsa.dot.gov				
	191.23 Reporting safety-related condition (SRCR)				
	191.25 Filing the SRCR within 5 days of determination, but not later than 10 days after discovery				
	191.27 Offshore pipeline condition reports – filed within 60 days after the inspections				
.605(d)	Instructions to enable operation and maintenance personnel to recognize potential **Safety Related Conditions**				

Comments:

49CFR PART 192

.13(c)		**CUSTOMER AND EFV INSTALLATION NOTIFICATION PROCEDURES**	**S**	**U**	**N/A**	**N/C**
	.16	Procedures for notifying new customers, within **90 days**, of their responsibility for those selections of service lines not maintained by the operator.				
	.381	If EFVs are installed, they must meet the performance requirements of §192.381				
	.383	If the operator has a voluntary installation program for excess flow valves, the program must meet the requirements outlined in §192.383.				
	.383	If the operator does not have a voluntary program for EFV installations, customers must be notified in accordance with §192.383.				

.605(a)		NORMAL OPERATING and MAINTENANCE PROCEDURES	S	U	N/A	N/C
	.605(a)	O&M Plan review and update procedure (**1 per year/15 months**)				
	.605(b)(3)	Making construction records, maps, and operating history available to appropriate operating personnel				
	.605(b)(5)	Start up and shut down of the pipeline to assure operation within **MAOP** plus allowable buildup				
	.605(b)(8)	Periodically reviewing the work done by operator's personnel to determine the effectiveness and adequacy of the procedures used in normal operation and maintenance and modifying the procedures when deficiencies are found				
	.605(b)(9)	Taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapors or gas, and making available when needed at the excavation, emergency rescue equipment, including a breathing apparatus and a rescue harness and line				
	.605(b)(10)	Routine inspection and testing of pipe-type or bottle-type holders				
	.605(b)(11)	Responding promptly to a report of a gas odor inside or near a building, unless the operator's emergency proced. under §192.615(a)(3) specifically apply to these reports.				
	.605(b)(12)	Implementing the applicable control room management procedures required by 192.631.				

Comments:

.605(a)		CHANGE in CLASS LOCATION PROCEDURES	S	U	N/A	N/C
	.609	Class location study				
	.611	Confirmation or revision of MAOP				

Comments:

.613		CONTINUING SURVEILLANCE PROCEDURES	S	U	N/A	N/C
	.613(a)	Procedures for surveillance and required actions relating to change in class location, failures (including cast iron circumferential cracking), leakage history, corrosion, substantial changes in CP requirements, and unusual operating and maintenance conditions (NTSB B.8)				
	.613(b)	Procedures requiring **MAOP** to be reduced, or other actions to be taken, if a segment of pipeline is in unsatisfactory condition				

Comments:

.605(a)		DAMAGE PREVENTION PROGRAM PROCEDURES	S	U	N/A	N/C
	.614(c)	Participation in a qualified one-call program, or if available, a company program that complies with the following:				

.605(a)	DAMAGE PREVENTION PROGRAM PROCEDURES	S	U	N/A	N/C
	(1) Identify persons who engage in excavating				
	(2) Provide notification to the public in the One Call area				
	(3) Provide means for receiving and recording notifications of pending excavations				
	(4) Provide notification of pending excavations to the members				
	(5) Provide means of temporary marking for the pipeline in the vicinity of the excavations				
	(6) Provides for follow-up inspection of the pipeline where there is reason to believe the pipeline could be damaged				
	(i) Inspection must be done to verify integrity of the pipeline				
	(ii) After blasting, a leak survey must be conducted as part of the inspection by the operator				

Comments:

.615		EMERGENCY PROCEDURES	S	U	N/A	N/C
	.615(a)(1)	Receiving, identifying, and classifying notices of events which require immediate response by the operator				
	.615(a)(2)	Establish and maintain communication with appropriate public officials regarding possible emergency				
	.615(a)(3)	Prompt response to each of the following emergencies:				
		(i) Gas detected inside a building				
		(ii) Fire located near or directly involving a pipeline				
		(iii) Explosion near or directly involving a pipeline				
		(iv) Natural disaster				
	.615(a)(4)	Availability of personnel, equipment, instruments, tools, and material required at the scene of an emergency				
	.615(a)(5)	Actions directed towards protecting people first, then property.				
	.615(a)(6)	Emergency shutdown or pressure reduction to minimize hazards to life or property				
	.615(a)(7)	Making safe any actual or potential hazard to life or property. Response should consider the possibility of leaks in multiple locations caused by excavation damage and underground migration of gas into nearby buildings. (NTSB B.9)				
	.615(a)(8)	Notifying appropriate public officials required at the emergency scene and coordinating planned and actual responses with these officials				
	.615(a)(9)	Instructions for restoring service outages after the emergency has been rendered safe				
	.615(a)(10)	Investigating accidents and failures as soon as possible after the emergency				
	.615(a)(11)	Actions required to be taken by a controller during an emergency in accordance with 192.631.				
	.615(b)(1)	Furnishing applicable portions of the emergency plan to supervisory personnel who are responsible for emergency action				
	.615(b)(2)	Training appropriate employees as to the requirements of the emergency plan and verifying effectiveness of training				
	.615(b)(3)	Reviewing activities following emergencies to determine if the procedures were effective				
	.615(c)	Establish and maintain liaison with appropriate public officials, such that both the operator and public officials are aware of each other's resources and capabilities in dealing with gas emergencies				

Comments:

Comments:

PUBLIC AWARENESS PROGRAM PROCEDURES (Also in accordance with API RP 1162)				S	U	N/A	N/C
.605(a)	**.616**	Public Awareness Program also in accordance with API RP 1162 (Amdt 192-99 pub. 5/19/05 eff. 06/20/05 and Amdt 192-not numbered pub 12/13/07 eff. 12/13/07).					
	.616(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 of a possible release;				
		(4)	Steps to be taken for public safety in the event of a gas pipeline release; and				
		(5)	Procedures to report such an event (to the operator).				
	.616(e)	The operator's program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations.					
	.616(f)	The operator's program and the media used must be comprehensive enough to reach all areas in which the operator transports gas.					
	.616(g)	The program must be conducted in English and any other languages commonly understood by a significant number of the population in the operator's area?					
	.616(h)	IAW API RP 1162, the operator's program should be reviewed for effectiveness within four years of the date the operator's program was first completed. <u>For operators in existence on June 20, 2005</u>, who must have completed their written programs no later than June 20, 2006, the first evaluation is due no later than **June 20, 2010**.					
	.616(j)	Operators of a master meter or petroleum gas system (unless the operator transports gas as a primary activity) must develop/implement a written procedure to provide its customers public awareness messages twice annually that includes: (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. (See this subpart for requirements for master meter or petroleum gas system operators not located on property controlled by the operator.)					

Comments:

.617	FAILURE INVESTIGATION PROCEDURES		S	U	N/A	N/C
	.617	Analyzing accidents and failures including laboratory analysis where appropriate to determine cause and prevention of recurrence				

Comments:

.605(a)	MAOP PROCEDURES	S	U	N/A	N/C
	.619 Establishing **MAOP** so that it is commensurate with the class location				
	MAOP cannot exceed the lowest of the following:				
	(a)(1) Design pressure of the weakest element				
	(a)(2) Test pressure divided by applicable factor				
	(a)(3) The highest actual operating pressure to which the segment of line was subjected during the 5 years preceding the applicable date in second column, unless the segment was tested according to .619(a)(2) after the applicable date in the third column or the segment was uprated according to subpart K.				
	(a)(4) Maximum safe pressure determined by operator.				
	(b) Overpressure protective devices must be installed if .619(a)(4) is applicable				
	(c) The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with § 192.611				
	.621 MAOP - High Pressure Distribution Systems Note: **D F** =0.32, or = 0.40 for PA-11 pipe produced after January 23, 2009 with a nominal pipe size (IPS or CTS) 4-inch or less, and a SDR of 11 or greater (i.e. thicker pipe wall), PA-11 design criteria in 192.121 & .123, (Final Rule Pub. 24 December, 2008)				
	.623 Max./Min. Allowable Operating Pressure - Low Pressure Distribution Systems				

Table for (a)(3):

Pipeline segment	Pressure date	Test date
- Onshore transmission line that was a gathering line not subject to this part before March 15, 2006.	March 15, 2006, or date line becomes subject to this part, whichever is later.	5 years preceding applicable date in second column.
All other pipelines.	July 1, 1970.	July 1, 1965.

Comments:

.13(c)	PRESSURE TEST PROCEDURES	S	U	N/A	N/C
	.503 Pressure testing				

Comments:

.605(a)	ODORIZATION of GAS PROCEDURES	S	U	N/A	N/C
	.625(a) Distribution lines must contain odorized gas. – must be readily detectable by person with normal sense of smell at $^{1}/_{5}$ of the LEL				
	.625(b) Odorized gas in **Class 3** or **4** locations (if applicable).				
	.625(f) Periodic gas sampling, using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable.				

Comments:

.605(a)	**TAPPING PIPELINES UNDER PRESSURE PROCEDURES**		S	U	N/A	N/C
	.627	Hot taps must be made by a qualified crew **NDT** testing is suggested prior to tapping the pipe. Reference API RP 2201 for **Best Practices**.				

Comments:

.605(a)	**PIPELINE PURGING PROCEDURES**		S	U	N/A	N/C
	.629	Purging of pipelines must be done to prevent entrapment of an explosive mixture in the pipeline				
		(a) Lines containing air must be properly purged.				
		(b) Lines containing gas must be properly purged				

Comments:

CONTROL ROOM MANAGEMENT PROCEDURES (Applies to Operator with greater than 250,000 services)				S	U	N/A	N/C
.605(a)	**.631(a)**	605(b)(12) Each operator must have and follow written control room management procedures. NOTE: *An operator must develop the procedures no later than August 1, 2011 and implement the procedures no later than February 1, 2013.*					
	.631(b)	The operator's program must define the roles and responsibilities of a controller during normal, abnormal and emergency conditions including a definition of:					
		(1)	Controller's authority and responsibility.				
		(2)	Controller's role when an abnormal operating condition is detected.				
		(3)	Controller's role during an emergency				
		(4)	A method of recording shift change responsibilities between controllers.				
	.631(c)	The operator's program must provide its controllers with the information, tools, processes and procedures necessary to perform each of the following:					
		(1) Implement sections 1, 4, 8,9,11.2, and 11.3 of API RP 1165 whenever a SCADA System is added, expanded or replaced.					
		(2) Conduct point-to-point verification between SCADA displays and related equipment when changes that affect pipeline safety are made.					
		(3) Test and verify any internal communications plan – at least once a year NTE 15 months.					
		(4) Test any backup SCADA system at least once each year but NTE 15 months.					
		(5) Establish and implement procedures for when a different controller assumes responsibility.					
	.631(d)	Each operator must implement and follow methods to reduce the risk associated with controller fatigue, including:					
		(1) Establishing shift lengths and schedule rotations that provide time sufficient to achieve eight hours of continuous sleep.					
		(2) Educating controllers and supervisors in fatigue mitigation strategies.					

CONTROL ROOM MANAGEMENT PROCEDURES (Applies to Operator with greater than 250,000 services)			S	U	N/A	N/C
		(3) Training of controllers and supervisors to recognize the effects of fatigue.				
		(4) Establishing a maximum limit on controller hours-of-service.				
	.631(e)	Each operator must have a written alarm management plan including these provisions:				
		(1) Reviewing alarms using a process that ensures that they are accurate and support safe operations.				
		(2) Identifying at least once a year, points that have been taken off SCADA scan or have had alarms inhibited, generated false alarms, or have had forced or manual values for periods of time exceeding that required for maintenance activities.				
		(3) Verifying the alarm set-point values and alarm descriptions once each year NTE 15 months.				
		(4) Reviewing the alarm management plan at least once every calendar year NTE 15 months.				
		(5) Monitoring the content and volume of activity being directed to and required of each controller once each year NTE 15 months.				
		(6) Addressing deficiencies identified through implementation of 1-5 of this section.				
	.631(f)	Each operator must assure that changes that could affect control room operations are coordinated with the control room personnel by performing the following:				
		(1) Establishing communications between controllers, management and field personnel when implementing physical changes to the pipeline.				
		(2) Requiring field personnel to contact the control room when emergency conditions exist and when field changes could affect control room operations.				
		(3) Seeking control room or management participation in planning prior to implementation of significant pipeline changes.				
	.631(g)	Each operator must assure that lessons learned from its experience are incorporated in to its procedures by performing the following:				
		(1) Reviewing reportable incidents to determine if control room actions contributed to the event and correcting any deficiencies.				
		(2) Including lessons learned from the operator's training program required by this section.				
	.631(h)	Each operator must establish a controller training program and review its contents once a year NTE 15 months which includes the following elements:				
		(1) Responding to abnormal operating conditions (AOCs).				
		(2) Using a computerized simulator or other method for training controllers to recognize AOCs				
		(3) Training controllers on their responsibilities for communication under the operator's emergency response procedures.				
		(4) Training that provides a working knowledge of the pipeline system, especially during AOCs.				
		(5) Providing an opportunity for controllers to review relevant procedures for infrequently used operating setups.				

Comments:

.605(a)	**MAINTENANCE PROCEDURES**		S	U	N/A	N/C
	.703(b)	Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service				
	(c)	Hazardous leaks must be repaired promptly				

Comments:

Comments:

.605(b)		**TRANSMISSION LINES - PATROLLING & LEAKAGE SURVEY PROCEDURES**	S	U	N/A	N/C
	.705(a)	Patrolling ROW conditions				
	(b)	Maximum interval between patrols of lines:				
	.706	Leakage surveys – **1 year/15 months**				
		Leak **detector equipment** survey requirements for lines transporting un-odorized gas				
		(a) **Class 3** locations - **7½ months** but at least **twice each calendar year**				
		(b) **Class 4** locations - **4½ months** but at least **4 times each calendar year**				

Class Location	At Highway and Railroad Crossings	At All Other Places
1 and 2	**2/yr (7½ months)**	**1/yr (15 months)**
3	**4/yr (4½ months)**	**2/yr (7½ months)**
4	**4/yr (4½ months)**	**4/yr (4½ months)**

Comments:

.605(b)		**DISTRIBUTION SYSTEM PATROLLING & LEAKAGE SURVEY PROCEDURES**	S	U	N/A	N/C
	.721(a)	Frequency of patrolling mains must be determined by the severity of the conditions which could cause failure or leakage (i.e., consider cast iron, weather conditions, known slip areas, etc.)				
	.721(b)	Mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage must be patrolled . . .				
	(b)(1)	In business districts at intervals not exceeding 4½ months, but at least four times each calendar year; and				
	(b)(2)	Outside business districts at intervals not exceeding 7½ months, but at least twice each calendar year				
	.723(a) & (b)	Periodic leak surveys determined by the nature of the operations and conditions.				
	(b)(1)	In business districts as specified, **1/yr (15 months)**				
	(b)(2)	Outside of business districts as specified, once every 5 calendar years/63 mos.; for unprotected lines subject to .465(e) where electrical surveys are impractical, once every 3 years/39 mos.				

Comments:

.605(b)		**LINE MARKER PROCEDURES**	S	U	N/A	N/C
	.707	Line markers installed and labeled as required				

Comments:

Comments:

.605(b)		TRANSMISSION RECORD KEEPING PROCEDURES	S	U	N/A	N/C
	.709	Records must be maintained…				
		(a) Repairs to the pipe – **life of system**				
		(b) Repairs to "other than pipe" – **5 years**				
		(c) Operation (Sub L) and Maintenance (Sub M) patrols, surveys, tests – **5 years** or until next one				

Comments:

.605(b)		TRANSMISSION FIELD REPAIR PROCEDURES	S	U	N/A	N/C
		Imperfections and Damages				
	.713(a)	Repairs of imperfections and damages on pipelines operating above **40% SMYS**				
		(1) Cut out a cylindrical piece of pipe and replace with pipe of ∃ design strength				
		(2) Use of a reliable engineering method				
	.713(b)	Reduce operating pressure to a safe level during the repair				
		Permanent Field Repair of Welds				
	.715	Welds found to be unacceptable under §192.241(c) must be repaired by:				
		(a) Taking the line out of service and repairing in accordance with **§192.245:**				
		▪ Cracks longer than **8%** of the weld length (except offshore) must be removed				
		▪ For each weld that is repaired, the defect must be removed down to clean metal and the pipe preheated if conditions demand it				
		▪ Repairs must be inspected to ensure acceptability				
		▪ Crack repairs or defect repairs in previously repaired areas must be done in accordance with qualified written welding procedures				
		(b) If the line remains in service, the weld may be repaired in accordance with **§192.245** if:				
		(1) The weld is not leaking				
		(2) The pressure is reduced to produce a stress that is **20% of SMYS or less**				
		(3) Grinding is limited so that **⅛ inch** of pipe weld remains				
		(c) If the weld cannot be repaired in accordance with **(a) or (b)** above, a full encirclement welded split sleeve must be installed				
		Permanent Field Repairs of Leaks				
	.717	Field repairs of leaks must be made as follows:				
		(a) Replace by cutting out a cylinder and replace with pipe similar or of greater design				
		(b)(1) Install a full encirclement welded split sleeve of an appropriate design unless the pipe is **joined by mechanical couplings** and **operates at less than 40% SMYS**				
		(b)(2) A leak due to a corrosion pit may be repaired by installing **a bolt on leak clamp**				
		(b)(3) For a corrosion pit leak, if a pipe is not more than **40,000 psi SMYS**, the pits may be repaired by **fillet welding a steel plate**. The plate must have **rounded corners** and the same **thickness or greater** than the pipe, and **not more than ½D** of the pipe size				

.605(b)		**TRANSMISSION FIELD REPAIR PROCEDURES**	S	U	N/A	N/C
		(b)(4) Submerged offshore pipe or pipe in inland navigable waterways may be repaired with a mechanically applied full encirclement split sleeve of appropriate design				
		(b)(5) Apply reliable engineering method				
		Testing of Repairs				
	.719(a)	Replacement pipe must be pressure tested to meet the requirements of a new pipeline				
	(b)	For lines of **6-inch diameter or larger** and that **operate at 20% of more of SMYS,** the repair must be nondestructively tested in accordance with **§192.241©**				

Comments:

.605(b)		**TEST REQUIREMENTS FOR REINSTATING SERVICE LINES**	S	U	N/A	N/C
	.725(a)	Except for .725(b), disconnected service lines must be tested the same as a new service line.				
	(b)	Service lines that are temporarily disconnected must be tested from the point of disconnection, the same as a new service line, before reconnect. See code for exception to this.				

Comments:

.605(b)		**ABANDONMENT or DEACTIVATION of FACILITIES PROCEDURES**	S	U	N/A	N/C
	.727(b)	Operator must disconnect both ends, purge, and seal each end before abandonment or a period of deactivation where the pipeline is not being maintained. Offshore abandoned pipelines must be filled with water or an inert material, with the ends sealed				
	(c)	Except for service lines, each inactive pipeline that is not being maintained under Part 192 must be disconnected from all gas sources/supplies, purged, and sealed at each end.				
	(d)	Whenever service to a customer is discontinued, do the procedures indicate one of the following:				
		(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				
	.727(g)	Operator must file reports upon abandoning underwater facilities crossing navigable waterways, including offshore facilities.				

Comments:

.605(b)		**PRESSURE LIMITING and REGULATING STATION PROCEDURES**	S	U	N/A	N/C
	.739(a)	Inspection and testing procedures for pressure limiting stations, relief devices, pressure regulating stations and equipment (**1 per yr/15 months**)				
		(1) In good mechanical condition				

.605(b)	PRESSURE LIMITING and REGULATING STATION PROCEDURES	S	U	N/A	N/C
	(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 correct pressures consistent with .201(a), except for .739(b).				
	(4) Properly installed and protected from dirt, liquids, and other conditions that may prevent proper oper.				
.739(b)	For steel lines if MAOP is determined per .619(c) and the MAOP is 60 psi (414 kPa) gage or more . . .				
	If MAOP produces hoop stress that: Is greater than 72 percent of SMYS — Then the pressure limit is: MAOP plus 4 percent; Is unknown as a percent of SMYS — Then the pressure limit is: A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP				
.741	Telemetering or Recording Gauges				
	(a) In place to indicate gas pressure in the district that is supplied by more than one regulating station				
	(b) Determine the need in a distribution system supplied by only one district station				
	(c) Inspect equipment and take corrective measures when indications of abnormally high or low pressure				
.743	Testing of Relief Devices				
.743	(a) Capacity must be consistent with .201(a) except for .739(b), and be determined **1 per yr/15 mo.**				
	(b) If calculated, capacities must be compared; annual review and documentation are required.				
	(c) If insufficient capacity, new or additional devices must be installed to provide required capacity.				

If MAOP produces hoop stress that	Then the pressure limit is:
Is greater than 72 percent of SMYS	MAOP plus 4 percent
Is unknown as a percent of SMYS	A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP

Comments:

.605(b)	VALVE AND VAULT MAINTENANCE PROCEDURES	S	U	N/A	N/C
	Transmission Valves				
.745	(a) Inspect and partially operate each transmission valve that might be required during an emergency (**1 per yr/15 months**)				
.745	(b) Prompt remedial action required, or designate alternative valve.				
	Distribution Valves				
.747	(a) Check and service each valve that may be necessary for the safe operation of a distribution system (**1 per yr/15 months**)				
	(b) Prompt remedial action required, or designate alternative valve.				

.605(b)	VAULT INSPECTION PROCEDURES	S	U	N/A	N/C
.749	Inspection of vaults greater than **200 cubic feet** and housing pressure regulating or limiting devices (**1 per yr NTE 15 months**).				

Comments:

.605(b)	PREVENTION of ACCIDENTAL IGNITION PROCEDURES	S	U	N/A	N/C
.751	Reduce the hazard of fire or explosion by:				
	(a) Removal of ignition sources in presence of gas and providing for a fire extinguisher				

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.605(b)	PREVENTION of ACCIDENTAL IGNITION PROCEDURES	S	U	N/A	N/C
	(b) Prevent welding or cutting on a pipeline containing a combustible mixture				
	(c) Post warning signs				

Comments:

.605(b)		CAULKED BELL AND SPIGOT JOINTS PROCEDURES	S	U	N/A	N/C
	.753	Cast-iron caulked bell and spigot joint repair:				
		(a) When subject to more than 25 psig, sealed with mechanical clamp, or sealed with material/device which does not reduce flexibility, permanently bonds, and seals and bonds as prescribed in §192.753(a)(2)(iii)				
		(b) When subject to 25 psig or less, joints, when exposed for any reason, must be sealed by means other than caulking				

.605(b)		PROTECTING CAST-IRON PIPELINE PROCEDURES	S	U	N/A	N/C
	.755	Operator has knowledge that the support for a segment of a buried cast-iron pipeline is disturbed must provide protection.				
		(a) Vibrations from heavy construction equipment, trains, trucks, buses or blasting?				
		(b) Impact forces by vehicles?				
		(c) Earth movement?				
		(d) Other foreseeable outside forces which might subject the segment of pipeline to a bending stress				
		(e) Provide permanent protection for the disturbed section as soon as feasible				

.13(c)		WELDING AND WELD DEFECT REPAIR/REMOVAL PROCEDURES	S	U	N/A	N/C
	.225	(a) Welding procedures must be qualified under **Section 5 of API 1104** or **Section IX of ASME Boiler and Pressure Code** by destructive test.				
		(b) Retention of welding procedure – details and test				
	.227	(a) Welders must be qualified by **Section 6 of API 1104 (19th Ed., 1999, including errata October31, 2001; and 20th edition 2007, including errata 2008)** or **Section IX of ASME Boiler and Pressure Code** (2004 ed. Including addenda through July 1, 2005) See exception in .227(b).				
		(b) Welders may be qualified under **section I of Appendix C** to weld on lines that operate at **< 20% SMYS.**				
	.229	(a) To weld on compressor station piping and components, a welder must successfully complete a destructive test				
		(b) Welder must have used welding process within the preceding **6 months**				
		(c) A welder qualified under .227(a)–				
	.229(c)	(1) May not weld on pipe that operates at $\geq$ 20% SMYS unless within the preceding 6 calendar months the welder has had one weld tested and found acceptable under the **sections 6 or 9 of API Standard 1104**; may maintain an ongoing qualification status by performing welds tested and found acceptable at least **twice per year**, not exceeding **7½ months**; may not requalify under an earlier referenced edition.				
		(2) May not weld on pipe that operates at < 20% SMYS unless is tested in accordance with .229(c)(1) or requalifies under .229(d)(1) or (d)(2).				
		(d) Welders qualified under .227(b) may not weld unless:				
		(1) Requalified within **1 year/15 months**, or				
		(2) Within **7½ months** but at least **twice per year** had a production weld pass a qualifying test				
	.231	Welding operation must be protected from weather				

.13(c)		WELDING AND WELD DEFECT REPAIR/REMOVAL PROCEDURES	S	U	N/A	N/C
	.233	Miter joints (**consider pipe alignment**)				
	.235	Welding preparation and joint alignment				
	.241	(a) Visual inspection must be conducted by an individual qualified by appropriate training and experience to ensure:				
		(1) Compliance with the welding procedure				
		(2) Weld is acceptable in accordance with **Section 9 of API 1104**				
		(b) Welds on pipelines to be **operated at 20% or more of SMYS** must be nondestructively tested in accordance with **192.243** except welds that are visually inspected and approved by a qualified welding inspector if:				
		(1) The nominal pipe diameter is less than **6 inches**, or				
		(2) The pipeline is to operate at a pressure that produces a hoop stress of less than **40% of SMYS** and the welds are so limited in number that nondestructive testing is impractical				
	.241	(c) Acceptability based on visual inspection or NDT is determined according to **Section 9 of API 1104.** If a girth weld is unacceptable under **Section 9** for a reason other than a crack, and if **Appendix A to API 1104** applies to the weld, the acceptability of the weld may be further determined under that appendix.				
		Repair and Removal of Weld Defects				
	.245	(a) Each weld that is unacceptable must be removed or repaired. Except for offshore pipelines, a weld must be removed if it has a crack that is more than **8%** 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 weld must be inspected and found acceptable.				
		(c) Repair of a crack or any other defect in a previously repaired area must be in accordance with a written weld repair procedure, qualified under **§192.225**				
		Note: Sleeve Repairs – use low hydrogen rod (**Best Practices –ref. API 1104 App. B, In Service Welding**)				

Comments:

.13(c)		NONDESTRUCTIVE TESTING PROCEDURES	S	U	N/A	N/C
	.243	(a) Nondestructive testing of welds must be performed by any process, other than trepanning, that clearly indicates defects that may affect the integrity of the weld				
		(b) Nondestructive testing of welds must be performed:				
		(1) In accordance with a written procedure, and				
		(2) By persons trained and qualified in the established procedures and with the test equipment used				
		(c) Procedures established for proper interpretation of each nondestructive test of a weld to ensure acceptability of the weld under **192.241©**				
		(d) When nondestructive testing is required under **§192.241(b)**, the following percentage of each day's field butt welds, selected at random by the operator, must be nondestructively tested over the entire circumference				
		(1) In **Class 1** locations at least **10%**				
		(2) In **Class 2** locations at least **15%**				
		(3) In **Class 3** and **4** locations, at crossings of a major navigable river, offshore, and within railroad or public highway rights-of-way, including tunnels, bridges, and overhead road crossings, **100%** unless impractical, then **90%**. Nondestructive testing must be impractical for each girth weld not tested.				
		(4) At pipeline tie-ins, **100%**				

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.13(c)	**NONDESTRUCTIVE TESTING PROCEDURES**	**S**	**U**	**N/A**	**N/C**
	(e) Except for a welder whose work is isolated from the principal welding activity, a sample of each welder's work for each day must be nondestructively tested, when nondestructive testing is required under **§192.241(b)**				
	(f) Nondestructive testing – the operator must retain, for the life of the pipeline, a record showing by mile post, engineering station, or by geographic feature, the number of welds nondestructively tested, the number of welds rejected, and the disposition of the rejected welds.				

Comments:

.273(b)		**JOINING of PIPELINE MATERIALS**	**S**	**U**	**N/A**	**N/C**
	.281	(a) 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) 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 Designation: D 2513.				
		(3) The joint may not be heated to accelerate the setting of the cement.				
		(c) Each heat-fusion joint on plastic pipe must comply with 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 piping, compresses the heated ends together, and holds the pipe in proper alignment while the plastic hardens.				
		(2) A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the joint uniformly and simultaneously to essentially the same temperature.				
		(3) An electrofusion joint must be joined utilizing the equipment and techniques of the fittings manufacturer or equipment and techniques shown, by testing joints to the requirements of §192.283(a)(1)(iii), to be at least equivalent to those of the fittings manufacturer.				
		(4) Heat may not be applied with a torch or other open flame.				
		(d) Each adhesive joint on plastic pipe must comply with the following:				
		(1) The adhesive must conform to ASTM Designation: D 2517.				
		(2) The materials and adhesive must be compatible with each other.				
		(e) Each compression type mechanical joint on plastic pipe must comply with the following:				
		(1) The gasket material in the coupling must be compatible with the plastic.				
		(2) A rigid internal tubular stiffener, other than a split tubular stiffener, must be used in conjunction with the coupling.				
	.283	(a) Before any written procedure established under §192.273(b) is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints made according to the procedure to the following tests:				
		(1) The burst test requirements of–				
		(i) Thermoplastic pipe: paragraph 6.6 (sustained pressure test) or paragraph 6.7 (Minimum Hydrostatic Burst Test) or paragraph 8.9 (Sustained Static pressure Test) of ASTM D2513				
		(ii) Thermosetting plastic pipe: paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Static Pressure Test) of ASTM D2517; or				
		(iii) Electrofusion fittings for polyethylene pipe and tubing: paragraph 9.1 (Minimum Hydraulic Burst Pressure Test), paragraph 9.2 (Sustained Pressure Test), paragraph 9.3 (Tensile Strength Test), or paragraph 9.4 (Joint Integrity Tests) of ASTM Designation F1055.				

.273(b)	JOINING of PIPELINE MATERIALS	S	U	N/A	N/C
	(2) For procedures intended for lateral pipe connections, subject a specimen joint made from pipe sections joined at right angles according to the procedure to a force on the lateral pipe until failure occurs in the specimen. If failure initiates outside the joint area, the procedure qualifies for use; and,				
	(3) For procedures intended for non-lateral pipe connections, follow the tensile test requirements of ASTM D638, except that the test may be conducted at ambient temperature and humidity If the specimen elongates no less than 25 percent or failure initiates outside the joint area, the procedure qualifies for use.				
	(b) Before any written procedure established under §192.273(b) is used for making mechanical plastic pipe joints that are designed to withstand tensile forces, the procedure must be qualified by subjecting five specimen joints made according to the procedure to the following tensile test:				
	(1) Use an apparatus for the test as specified in ASTM D 638 (except for conditioning).				
	(2) The specimen must be of such length that the distance between the grips of the apparatus and the end of the stiffener does not affect the joint strength.				
	(3) The speed of testing is 0.20 in. (5.0 mm) per minute, plus or minus 25 percent.				
	(4) Pipe specimens less than 4 inches (102 mm) in diameter are qualified if the pipe yields to an elongation of no less than 25 percent or failure initiates outside the joint area.				
	(5) Pipe specimens 4 inches (102 mm) and larger in diameter shall be pulled until the pipe is subjected to a tensile stress equal to or greater than the maximum thermal stress that would be produced by a temperature change of 100° F (38° C) or until the pipe is pulled from the fitting. If the pipe pulls from the fitting, the lowest value of the five test results or the manufacturer's rating, whichever is lower must be used in the design calculations for stress.				
	(6) Each specimen that fails at the grips must be retested using new pipe.				
	(7) Results pertain only to the specific outside diameter, and material of the pipe tested, except that testing of a heavier wall pipe may be used to qualify pipe of the same material but with a lesser wall thickness.				
	(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.				
	.285 (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) applicable to the type of joint and material being tested;				
	(ii) Examined by ultrasonic inspection and found not to contain flaws that may cause failure; or				
	(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 requalified under an applicable procedure, if during any 12-month period that person:				
	(1) Does not make any joints under that procedure; or				
	(2) Has 3 joints or 3 percent of the joints made, whichever is greater, under that procedure that are 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.				

.273(b)		**JOINING of PIPELINE MATERIALS**	**S**	**U**	**N/A**	**N/C**
	.287	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.				

Comments:

.605(b)		**CORROSION CONTROL PROCEDURES**	**S**	**U**	**N/A**	**N/C**
	.453	Are corrosion procedures established and carried out by or under the direction of a qualified person for:				
		▪ Design				
		▪ Operations				
		▪ Installation				
		▪ Maintenance				
	.455	(a) (b) For pipelines installed **after July 31, 1971**, buried segments must be externally coated and cathodically protected within **one year** after construction (see exceptions in code)				
		(c) Aluminum may not be installed in a buried or submerged pipeline if exposed to an environment with a natural **pH in excess of 8** (see exceptions in code)				
	.457	(a) All effectively coated steel transmission pipelines installed prior to **August 1, 1971**, must be cathodically protected				
		(b) If installed **before August 1, 1971**, cathodic protection must be provided in areas of active corrosion for: bare or ineffectively coated transmission lines, and bare or coated c/s, regulator sta., meter sta. piping, and (except for cast iron or ductile iron) bare or coated distribution lines.				
	.459	Examination of buried pipeline when exposed: if corrosion is found, further investigation is required (Note: To include graphitization on cast iron or ductile iron pipe. NTSB B.7)				
	.461	Procedures must address the protective coating requirements of the regulations. External coating on the steel pipe must meet the requirements of this part.				
	.463	Cathodic protection level according to **Appendix D** criteria				
	.465	(a) Pipe-to-soil monitoring (**1 per yr/15 months**) or short sections (**10% per year, all in 10 years**)				
		(b) Rectifier monitoring (**6 per yr/2½ months**)				
		(c) Interference bond monitoring (**as required**)				
		(d) Prompt remedial action to correct any deficiencies indicated by the monitoring				
	.465	(e) Electrical surveys (closely spaced pipe to soil) on bare/unprotected lines, cathodically protect active corrosion areas (**1 per 3 years/39 months**)				
	.467	Electrical isolation (**include casings**)				
	.469	Sufficient test stations to determine CP adequacy				
	.471	Test lead maintenance				
	.473	Interference currents				
	.475	(a) Proper procedures for transporting corrosive gas?				
		(b) Removed pipe must be inspected for internal corrosion. If found, the adjacent pipe must be inspected to determine extent. Certain pipe must be replaced. Steps must be taken to minimize internal corrosion.				
	.476	Systems designed to reduce internal corrosion Amdt 192-(no number) Pub. 4/23/07, eff. 5/23/07 (a) New construction				
		(b) Exceptions – offshore pipeline and systems replaced before 5/23/07				
		(c) Evaluate impact of configuration changes to existing systems				
	.477	Internal corrosion control coupon (or other suit. Means) monitoring (**2 per yr/7½ months)**				
	.479	(a) Each exposed pipe must be cleaned and coated (see exceptions under **.479(c)**)				

.605(b)	**CORROSION CONTROL PROCEDURES**	S	U	N/A	N/C
	Offshore splash zones and soil-to-air interfaces must be coated				
	(b) Coating material must be suitable				
	Coating is not required where operator has proven that corrosion will:				
	(c) (1) Only be a light surface oxide, or				
	(2) Not affect safe operation before next scheduled inspection				
.481	(a) Atmospheric corrosion control monitoring (**1 per 3 yrs/39 months onshore; 1 per yr/15 months offshore**)				
.481	(b) Special attention required at soil/air interfaces, thermal insulation, under disbonded coating, pipe supports, splash zones, deck penetrations, spans over water				
.481	(c) Protection must be provided if atmospheric corrosion is found (**per §192.479**)				
.483	Replacement and required pipe must be coated and cathodically protected (see code for exceptions)				
.485	(a) Procedures to replace pipe or reduce the **MAOP** if general corrosion has reduced the wall thickness?				
	(b) Procedures to replace/repair pipe or reduce **MAOP** if localized corrosion has reduced wall thickness (unless reliable engineering repair method exists)?				
	(c) Procedures to use **Rstreng** or **B-31G** to determine remaining wall strength?				
.487	Remedial measures (distribution lines other than cast iron or ductile iron)				
.489	(a) 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) Each segment of cast iron or ductile iron pipe where localized graphitization is found it must be assessed and remediated according to this subpart.				
.491	Corrosion control maps and record retention (**pipeline service life or 5 yrs**)				

Comments:

.801-.809	**Subpart N — Qualification of Pipeline Personnel Procedures**	S	U	N/A	N/C
	Refer to Operator Qualification Inspection Forms and Protocols (OPS web site)				

.901-.951	**Subpart O — Pipeline Integrity Management**	S	U	N/A	N/C
	This form does not cover Gas Pipeline Integrity Management Programs				

Subparts A - C	**PART 199 – DRUG and ALCOHOL TESTING REGULATIONS and PROCEDURES**	S	U	N/A	N/C
	Drug & Alcohol Testing & Alcohol Misuse Prevention Program – Use PHMSA Form # 13, PHMSA 2008 Drug and Alcohol Program Check.				

Comments:

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PIPELINE INSPECTION (Field)		S	U	N/A	N/C
.179	Valve Protection from Tampering or Damage				
.463	Cathodic Protection				
.465	Rectifiers				
.476	Systems designed to reduce internal corrosion				
.479	Pipeline Components Exposed to the Atmosphere				
.605	Knowledge of Operating Personnel				
.707	ROW Markers, Road and Railroad Crossings				
.719	Pre-pressure Tested Pipe (**Markings and Inventory**)				
.741	Telemetering, Recording gauges				
.739/.743	Pressure Limiting and Regulating Devices (spot-check field installed equipment vs. inspection records)				
.745	Valve Maintenance				
.751	Warning Signs				
.801 - .809	Operator Qualification - Use PHMSA Form 15 Operator Qualification Field Inspection Protocol Form				

Comments:

REGULATORY REPORTING PERFORMANCE AND RECORDS		S	U	N/A	N/C
191.5	Telephonic reports to NRC				
191.15	Written incident reports; supplemental incident reports **(Form F 7100.2)**				
191	Annual Reports (**Forms 7100.1-1, 7100.2-1)**				
191.23	Safety related condition reports				
192.16	Customer Notification (**Verification – 90 days – and Elements**)				
192.727(g)	Abandoned facilities offshore, onshore crossing commercially navigable waterways reports				

CONSTRUCTION PERFORMANCE AND RECORDS		S	U	N/A	N/C
.225	Test Results to Qualify Welding Procedures				
.227	Welder Qualification				
.241 (a)	Visual Weld Inspector Training/Experience				
.243 (b)(2)	Nondestructive Technician Qualification				
(c)	NDT procedures				
(f)	Total Number of Girth Welds				
(f)	Number of Welds Inspected by NDT				
(f)	Number of Welds Rejected				
(f)	Disposition of each Weld Rejected				
.273/.283	Qualified Joining Procedures Including Test Results				
.285	Personnel Joining Qualifications				
.287	Joining Inspection Qualifications				
.303	Construction Specifications				
.325	Underground Clearance				

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CONSTRUCTION PERFORMANCE AND RECORDS		S	U	N/A	N/C
.327	Amount, Location, Cover of each Size of Pipe Installed				
.383(e)	EFV customer notification				
.455	Cathodic Protection				

OPERATIONS and MAINTENANCE PERFORMANCE AND RECORDS			S	U	N/A	N/C
.517 (a)		Pressure Testing (operates at or above 100 psig) – **useful life of pipeline**				
.517 (b)		Pressure Testing (operates below 100 psig, service lines, plastic lines) – **5 years**				
.603(b)	.605(a)	Procedural Manual Review – Operations and Maintenance (**1 per yr/15 months**)				
	.605(b)(3)	Availability of construction records, maps, operating history to operating personnel				
	.605(b)(8)	Periodic review of personnel work – effectiveness of normal O&M procedures				
	.605(c)(4)	Periodic review of personnel work – effectiveness of abnormal operation procedures				
.709	.614	Damage Prevention (**Miscellaneous**)				
	.609	Class Location Study (**If Applicable**)				
.603(b)	.615(b)(1)	Location Specific Emergency Plan				
	.615(b)(2)	Emergency Procedure training, verify effectiveness of training				
	.615(b)(3)	Employee Emergency activity review, determine if procedures were followed.				
	.615(c)	Liaison Program with Public Officials				
	.616	Public Awareness Program				
	.616(e & f)	Documentation properly and adequately reflects implementation of operator's Public Awareness Program requirements - Stakeholder Audience identification, message type and content, delivery method and frequency, supplemental enhancements, program evaluations, etc. (i.e. contact or mailing rosters, postage receipts, return receipts, audience contact documentation, etc. for emergency responder, public officials, school superintendents, program evaluations, etc.). See table below:				

API RP 1162 Baseline* Recommended Message Deliveries	
Stakeholder Audience (Natural Gas Transmission Line Operators)	**Baseline Message Frequency (starting effective date of Plan)**
Residents Along Right-of-Way and Places of Congregation	2 years
Emergency Officials	Annual
Public Officials	3 years
Excavator and Contractors	Annual
One-Call Centers	As required of One-Call Center
Stakeholder Audience (Gathering Line Operators)	**Baseline Message Frequency (starting from effective date of Plan)**
Residents and Places of Congregation	Annual
Emergency Officials	Annual
Public Officials	3 years
Excavators and Contractors	Annual
One-Call Centers	As required of One-Call Center
Stakeholder Audience (LDCs)	**Baseline Message Frequency (starting from effective date of Plan)**
Residents Along Local Distribution System	Annual
LDC Customers	Twice annually
Emergency Officials	Annual
Public Officials	3 years
Excavator and Contractors	Annual
One-Call Centers	As required of One-Call Center
* Refer to API RP 1162 for additional requirements, including general program recommendations, supplemental requirements, recordkeeping, program evaluation, etc.	

			S	U	N/A	N/C
	.616(g)	The program must be conducted in English and any other languages commonly understood by a significant number of the population in the operator's area.				
	.616(h)	Effectiveness Review of operator's program.				

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	OPERATIONS and MAINTENANCE PERFORMANCE AND RECORDS		S	U	N/A	N/C
	.616(j)	Operators of a master meter or petroleum gas systems - public awareness messages 2 times annually: (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.				
	.617	Failure Investigation Reports (Note: Also include reported third party damage and leak response records. NTSB B.10)				
.517		Pressure Testing				
.709	.619 .621 .623	Maximum Allowable Operating Pressure (**MAOP**) Note: New PA-11 design criteria is incorporated into 192.121 & .123. (Final Rule Pub. 24 December, 2008)				
	.625	Odorization of Gas				
	.705	Patrolling (**Refer to Table Below**)				

Class Location	**At Highway and Railroad Crossings**	**At All Other Places**
1 and 2	**2/yr (7½ months)**	**1/yr (15 months)**
3	**4/yr (4½ months)**	**2/yr (7½ months)**
4	**4/yr (4½ months)**	**4/yr (4½ months)**

			S	U	N/A	N/C
.709	.706	Leak Surveys (**Refer to Table Below**)				

Class Location	**Required**	**Not Exceed**
1 and 2	**1/yr**	**15 months**
3	**2/yr***	**7½ months**
4	**4/yr***	**4½ months**

* Leak **detector equipment** survey required for lines transporting un-odorized gas.

			S	U	N/A	N/C
.603(b)	.721(b)(1)	Patrolling Business District (**4 per yr/4½ months**)				
	.721(b)(2)	Patrolling Outside Business District (**2 per yr/7½ months**)				
	.723(b)(1)	Leakage Survey – business District (**1 per yr/15 months**)				
	.723(b)(2)	Leakage Survey				
		▪ Outside Business District (**5 years**)				
		▪ Cathodically unprotected distribution lines (**3 years**)				
	.725	Tests for reinstating service lines				
.603b/.727g	.727	Abandoned Pipelines; Underwater Facility Reports				
.709	.739	Pressure Limiting and Regulating Stations (**1 per yr/15 months**)				
	.743	Pressure Limiting and Regulator Stations – Capacity (**1 per yr/15 months**)				
	.745	Valve Maintenance Transmission Lines (**1 per yr/15 months**)				
.603(b)	.747	Valve Maintenance Distribution Lines (**1 per yr/15 months**)				
.709	.749	Vault Maintenance (**∃200 cubic feet**)(**1 per yr/15 months**)				
.603(b)	.751	Prevention of Accidental Ignition (hot work permits)				
	.755	Caulked Bell and Spigot Joint Repair				
	.225(b)	Welding – Procedure				
	.227/.229	Welding – Welder Qualification				
	.243(b)(2)	NDT – NDT Personnel Qualification				
	.283	Joining - Procedures				
	.285	Joining - Personnel Qualifications				
	.287	Joining - Inspector Qualifications				

STANDARD INSPECTION REPORT OF A GAS DISTRIBUTION OPERATOR

Unless otherwise noted, all code references are to 49CFR Part 192. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked

If an item is marked U, N/A, or N/C, an explanation must be included in this report.

OPERATIONS and MAINTENANCE PERFORMANCE AND RECORDS			S	U	N/A	N/C
.709	.243(f)	NDT Records (**Pipeline Life**)				
		Repair: pipe (**Pipeline Life**); Other than pipe (**5 years**)				
.807(b)	Refer to PHMSA Form # 15 to document review of operator's employee covered task records					

Comments:

CORROSION CONTROL PERFORMANCE AND RECORDS			S	U	N/A	N/C
.491	.491(a)	Maps or Records				
.491	.459	Examination of Buried Pipe when Exposed				
.491	.465(a)	Annual Pipe-to-soil Monitoring (**1 per yr/15 months**) for short sections (**10% per year; all in 10 years**)				
.491	.465(b)	Rectifier Monitoring (**6 per yr/2½ months**)				
.491	.465(c)	Interference Bond Monitoring – Critical (**6 per yr/2½ months**)				
.491	.465(c)	Interference Bond Monitoring – Non-critical (**1 per yr/15 months**)				
.491	.465(d)	Prompt Remedial Actions				
.491	.465(e)	Unprotected Pipeline Surveys, CP active corrosion areas (**1 per 3 cal yr/39 months**)				
.491	.467	Electrical Isolation (**Including Casings**)				
.491	.469	Test Stations – Sufficient Number				
.491	.471	Test Lead Maintenance				
.491	.473	Interference Currents				
.491	.475(a)	Internal Corrosion; Corrosive Gas Investigation				
.491	.475(b)	Internal Corrosion; Internal Surface Inspection; Pipe Replacement				
.491	.476 (d)	Internal Corrosion; New system design; Evaluation of impact of configuration changes to existing systems				
.491	.477	Internal Corrosion Control Coupon Monitoring (**2 per yr/7½ months**)				
.491	.481	Atmospheric Corrosion Control Monitoring (**1 per 3 cal yr/39 months onshore; 1 per yr/15 months offshore**)				
.491	.483/.485	Remedial: Replaced or Repaired Pipe; coated and protected; corrosion evaluation and actions				

Comments:

Attachment 1
Distribution Operator Compressor Station Inspection

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If an item is marked U, N/A, or N/C, an explanation must be included in this report.

.605(b)		COMPRESSOR STATION PROCEDURES	S	U	N/A	N/C
	.605(b)(6)	Maintenance procedures, including provisions for isolating units or sections of pipe and for purging before returning to service				
	.605(b)(7)	Starting, operating, and shutdown procedures for gas compressor units				
	.731	Inspection and testing procedures for remote control shutdowns and pressure relieving devices (**1 per yr/15 months**), prompt repair or replacement				
	.735	(a) Storage of excess flammable or combustible materials at a safe distance from the compressor buildings				
		(b) Tank must be protected according to **NFPA #30**				
	.736	Compressor buildings in a compressor station must have fixed gas detection and alarm systems (**must be performance tested**), unless:				
		▪ **50% of the upright side areas** are permanently open, or				
		▪ It is an unattended field compressor station of **1000 hp or less**				

Comments:

		COMPRESSOR STATIONS INSPECTION (Field) (Note: Facilities may be "Grandfathered")	S	U	N/A	N/C
.163	(c)	Main operating floor must have (at least) two (2) separate and unobstructed exits				
		Door latch must open from inside without a key				
		Doors must swing outward				
	(d)	Each fence around a compressor station must have (at least) 2 gates or other facilities for emergency exit				
		Each gate located within 200 ft of any compressor plant building must open outward				
		When occupied, the door must be opened from the inside without a key				
	(e)	Does the equipment and wiring within compressor stations conform to the **National Electric Code, ANSI/NFPA 70?**				
.165	(a)	If applicable, are there liquid separator(s) on the intake to the compressors?				
	(b)	Do the liquid separators have a manual means of removing liquids?				
		If slugs of liquid could be carried into the compressors, are there automatic dumps on the separators, Automatic compressor shutdown devices, or high liquid level alarms?				
.167	(a)	ESD system must:				
		- Discharge blowdown gas to a safe location				
		- Block and blowdown the gas in the station				
		- Shut down gas compressing equipment, gas fires, electrical facilities in compressor building and near gas headers				
		- Maintain necessary electrical circuits for emergency lighting and circuits needed to protect equipment from damage				
		ESD system must be operable from at least two locations, each of which is:				
		- Outside the gas area of the station				
		- Not more than 500 feet from the limits of the station				
		- ESD switches near emergency exits?				
	(b)	For stations supplying gas directly to distribution systems, is the ESD system configured so that the LDC will not be shut down if the ESD is activated?				
	(c)	Are ESDs on platforms designed to actuate automatically by…				
		- For unattended compressor stations, when:				

Attachment 1
Distribution Operator Compressor Station Inspection

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If an item is marked U, N/A, or N/C, an explanation must be included in this report.

	COMPRESSOR STATIONS INSPECTION (Field) (Note: Facilities may be "Grandfathered")	**S**	**U**	**N/A**	**N/C**
	▪ The gas pressure equals MAOP plus 15%?				
	▪ An uncontrolled fire occurs on the platform?				
	- For compressor station in a building, when				
	▪ An uncontrolled fire occurs in the building?				
	▪ Gas in air reaches 50% or more of LEL in a building with a source of ignition (facility conforming to **NEC Class 1, Group D** is not a source of ignition)?				
.171 (a)	Does the compressor station have adequate fire protection facilities? If fire pumps are used, they must not be affected by the ESD system.				
(b)	Do the compressor station prime movers (other than electrical movers) have over-speed shutdown?				
(c)	Do the compressor units alarm or shutdown in the event of inadequate cooling or lubrication of the unit(s)?				
(d)	Are the gas compressor units equipped to automatically stop fuel flow and vent the engine if the engine is stopped for any reason?				
(e)	Are the mufflers equipped with vents to vent any trapped gas?				
.173	Is each compressor station building adequately ventilated?				
.457	Is all buried piping cathodically protected?				
.481	Atmospheric corrosion of aboveground facilities				
.603	Does the operator have procedures for the start-up and shut-down of the station and/or compressor units?				
	Are facility maps current/up-to-date?				
.615	Emergency Plan for the station on site?				
.619	Review pressure recording charts and/or SCADA				
.707	Markers				
.731	Overpressure protection – reliefs or shutdowns				
.735	Are combustible materials in quantities exceeding normal daily usage, stored a safe distance from the compressor building?				
	Are aboveground oil or gasoline storage tanks protected in accordance with **NFPA standard No. 30?**				
.736	Gas detection – location				

Comments:

	COMPRESSOR STATION O&M PERFORMANCE AND RECORDS		**S**	**U**	**N/A**	**N/C**
.709	.731(a)	Compressor Station Relief Devices (**1 per yr/15 months**)				
	.731(c)	Compressor Station Emergency Shutdown (**1 per yr/15 months**)				
	.736(c)	Compressor Stations – Detection and Alarms (**Performance Test**)				

Comments:

Recent PHMSA Advisory Bulletins (Last 2 years)

Leave this list with the operator.

All PHMSA Advisory Bulletins (Last 2 years)

Number	Date	Subject
ADB-09-01	May 21, 2009	Pipeline Safety: Potential Low and Variable Yield and Tensile Strength and Chemical Composition Properties in High Strength Line Pipe
ADB-09-02	September 30, 2009	Pipeline Safety: Weldable Compression Coupling Installation
ADB-09-03	December 7, 2009	Pipeline Safety: Operator Qualification (OQ) Program Modifications
ADB-09-04	January 19, 2010	Pipeline Safety: Reporting Drug and Alcohol Test Results for Contractors and Multiple Operator Identification Numbers
ADB-10-02	February 3, 2010	Pipeline Safety - Implementation of Revised Incident/Accident Report Forms for Distribution Systems, Gas Transmission and Gathering Systems, and Hazardous Liquid Systems
ADB-10-03	March 24, 2010	Pipeline Safety: Girth Weld Quality Issues Due to Improper Transitioning, Misalignment, and Welding Practices of Large Diameter Line Pipe
ADB-10-04	April 29, 2010	Pipeline Safety: Implementation of Electronic Filing for Recently Revised Incident/Accident Report Forms for Distribution Systems, Gas Transmission and Gathering Systems, and Hazardous Liquid Systems
ADB-10-06	August 3, 2010	Pipeline Safety: Personal Electronic Device Related Distractions
ADB-10-08	November 3, 2010	Pipeline Safety: Emergency Preparedness Communications
ADB-11-01	January 4, 2011	Pipeline Safety: Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation
ADB-11-02	February 9, 2011	Dangers of Abnormal Snow and Ice Build-up on Gas Distribution Systems

For more PHMSA Advisory Bulletins, go to http://phmsa.dot.gov/pipeline/regs/advisory-bulletin