Luis Escobar
GPTC Secretary
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December 1, 2024

Dear *Guide* Purchaser,

Enclosed is ANSI/GPTC Z380.1, *Guide for Gas Transmission, Distribution, and Gathering Piping Systems,* 2022 Edition, which includes Addenda 1, 2, 3, 4, and 5.

Your purchase entitles you to receive future notification of the issuance of addenda. Addenda are formatted to enable the replacement of pages in your *Guide* with updated pages. Addenda are available for free downloading from the GPTC webpage at www.aga.org/gptc or paper copies may be purchased at https://www.aga.org/aga-publications for a nominal fee.

On behalf of the Gas Piping Technology Committee and the American Gas Association, thank you for your purchase and interest in the *Guide*.

Sincerely,

Secretary
GPTC Z380

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GPTC GUIDE FOR GAS TRANSMISSION, DISTRIBUTION, AND GATHERING PIPING SYSTEMS

2022 EDITION

Addendum 5, December 2024

The changes in this edition are marked by wide vertical lines inserted to the left of modified text, overwriting the left border of most tables, or a block symbol (▌) where needed. There were no Federal Regulation update(s) for this period. 19 GPTC transactions affected 22 sections of the Guide.

Editorial updates include application of the Editorial Guidelines, adjustments to page numbering, and adjustment of text on pages. Only significant editorial updates are marked. Editorial updates as indicated "EU" affected 6 sections of the Guide. Most sections were impacted by page adjustments throughout the guide.

The table shows the affected sections, the pages to be removed, and their replacement pages.

Key to Reasons for Change
Amdt.19X-XXX or docket number: federal regulation amendment TR YY-XX: GPTC transaction with new or updated guide material EU: editorial update

Guide Section	Reason for Change	Pages to be Removed	Replacement Pages
FOREWORD	TR 2017-04	xvi, xx, xxii, xxiii, xxiv	xvi, xx(a), xxi, xxii, xxiii
Front of Guide/Committee Scope	TR 2021-42	xxiii	xxii
Historical Reconstruction	TR 2022-43	xxxi/xxxvi/xxxvii/xxxviii/xxxix/xl/xli/xlii/xliii/xliv/xlv/xlvi/xlvii/xlviii/xlix/l/li/lii/liii/liv/lv/lvi/lvii/lviii/lix/lx/lxi/lxii/lxiii/lxiv/lxv/lxvi/lxvii/lxviii/lxviii	xxxi/xxxiv/xxxv/xxxvi/xxxvii/xxxviii/xxxix/xl/xli/xlii/xliii/xliv/xlv/xlvi/xlvii/xlvii(a)/xlviii/xlix/l/li/lii/liii/liv/lv/lvi/lvii/lviii/lix/lx/lxi/lxii/lxiii/lxiv/lxv/lxvi/lxvii/lxviii/lxix/lxx/lxxi/lxxii/lxxiii/lxxiv
Part 191			
191.9	TR 2023-01	7	7
191.11	TR 2023-01	8	8
191.13	TR 2023-01	9	9
191.15	TR 2023-01	10	10
191.17	TR 2023-01	11	11
Part 192			
192.8	TR 2021-42, TR 2023-20, TR 2022-45	41, 42, 44	41, 42, 44
192.12	TR 2020-08	52/53/53/54/55/56/57/58/59	51/52/53/54/55/55a/55b/56/57/58/59
192.14	TR 2021-42	55/56/57/58/59	56/57/58/59
192.103	TR 2022-40	69/70	69/70
192.121	TR 2021-42	91	91

Guide Section	Reason for Change	Pages to be Removed	Replacement Pages
192.179	TR 2022-30	132/132a/133/134/135/136/137/138/139/139/141/141/143/144/144a/145/146	132/132a/133/134/135/136/137/138/139/140/141/142/143/144/144a/145/146
192.285	TR 2021-13	170/171	170/171
192.321	TR 2021-34	184/185/186/187/188/189/190/191/192/193/194/195	184/185/186/187/188/189/190/191/192/193/194/195
192.381	TR 2021-41	216	216
192.383	TR 2021-41	218/218a	218/218a
192.385	TR 2021-41, TR 2023-19	220b, 220b	220b, 220b
192.605	TR 2018-32, TR 2021-42, TR 2022-47	291/292/293/294/295, 290, 286/287/287a	291/291a/292/293/294/295/296/297/298, 290, 286/287/287a
192.609	TR 2021-28	295/296/297/298/298b/298b/298b/298c/299/300/301/302	295/296/297/297a/297b/297c/298/299/299a/300/301/302
192.613	TR 2022-40, TR 2023-14	311/311a/313//313, 302/303/303/304/305a	311/311a/312/313, 302/302a/303/304/305
192.615	TR 2021-42	324	324
192.616	TR 2021-42	330	330
192.631	TR 2021-42	375b	375b
192.707	TR 2021-42, TR 2023-10	391/392/392/393a, 391/392/392/393a	391/392/393/393a, 391/392/393/393a
192.713	TR 2021-42	398	398
192.727	TR 2021-42	406	406
192.751	TR 2021-42	409/410/411/412/413/414/415/416/417/418/419/420/421/422/422/424/425/426/427/428	408/409/410/411/412/413/414/415/416/417/418/419/420/421/422/423/424/425/425a/426
192.755	TR 2022-40	425	425a
192.801	TR 2021-42	432	432
192.901	TR 2021-42	440	440
192.915	TR 2017-25	465/466/466	465/465a/466
192.917	TR 2021-42, TR 2022-40	472/473/474, 483	472/473/474, 483
192.935	TR 2022-50	565/566/566a	565/566/566a
GMA G-191-2	TR 2023-01	617	617
GMA G-192-1	TR 2017-25, TR 2020-08, TR 2022-40	649/650, 663/663a, 644/645/646/647/647a/648/649/649a/650/662/663/663a	649/650, 663/663a, 645/645a/646/647/648/649/650/662/663/663a
GMA G-192-3	TR 2021-42	688	688
GMA G-192-5	TR 2019-16	712	712
GMA G-192-8	TR 2021-42, TR 2023-03	728/739, 742	728/739, 742
GMA G-192-13	TR 2022-40	818/819/820/821/821	818/819/820/820a/821
GMA G-192-14	TR 2021-42	823/825	823/825

Guide for Gas Transmission, Distribution, and Gathering Piping Systems

2022 Edition

Addendum 5, December 2024

An American National Standard

Author:
Gas Piping Technology Committee (GPTC) Z380
Accredited by ANSI

Secretariat:
American Gas Association

Approved by
American National Standards Institute (ANSI)
Date: March 1, 2022

ANSI GPTC Z380.1-2022,
Catalog Number: Z380

PLEASE NOTE

Addenda to this Guide will also be issued periodically to enable users to keep the Guide up-to-date by replacing the pages that have been revised with the new pages. It is advisable, however, that pages which have been revised be retained so that the chronological development of the Federal Regulations and the Guide is maintained.

CAUTION

As part of document purchase, GPTC (using AGA as Secretariat) will try to keep purchasers informed on the current Federal Regulations as released by the Department of Transportation (DOT). This is done by periodically issuing addenda to update both the Federal Regulations and the guide material. It is the responsibility of the purchaser to obtain a copy of any addenda. Addenda are posted on the Committee's webpage at www.aga.org/gptc. The GPTC assumes no responsibility in the event the purchaser does not obtain addenda. The purchaser is reminded that the changes to the Regulations can be found on the Federal Register's web site.

Participation by state and federal agency representative(s) or person(s) affiliated with industry is not to be interpreted as government or industry endorsement of the guide material in this Guide.

Conversions of figures to electronic format courtesy of ViaData Incorporated.

Cover photos of meters and pipeline with gauge provided by permission of Spire Inc. (formerly Laclede Gas Company); cover photo of welder provided by permission of the Southern California Gas Company.

The historical reconstruction of the Regulations is available in AGA X69804, "Historical Collection of Natural Gas Pipeline Safety Regulations." It includes the original version of Parts 191 and 192 and all their amendments through Amdts. 191-15 and 192-93 (published September 15, 2003). The Federal Register preamble to the amendments is included as well. This collection of all earlier amendments has been established as a readily accessible reference to supplement the Guide or to aid research activity. However, considering the electronic availability of amendments starting in 2004, refer to the Federal Register web site for later amendments.

The format of the Guide includes the title of each numbered section of the Regulations and is followed by the effective date of the latest amendment activity or effective date of the original version if no amendment has been issued. The Regulation is followed by a list of amendment or control numbers for the respective section and the applicable guide material as developed by the Committee.

The Guide is maintained using the continuous maintenance process.

(1) Guide material is reviewed and, where applicable, updated when PHMSA amends regulations or publishes an advisory bulletin.
(2) The Committee acknowledges that other PHMSA documents, such as Inspection Protocols, FAQs, and Enforcement Guidance, may be used in the development of guide material. However, the guide material will not typically include a specific reference to such documents.

Proposals to revise any guide material may be submitted to the Committee at any time. A *Form for Proposals on ANSI GPTC Z380.1* is provided at the end of the Guide and may also be obtained on the GPTC website at www.aga.org/gptc. Use that form to describe and justify the proposal and submit it to: GPTC Secretary, American Gas Association, 400 N. Capitol Street, NW, Washington, D.C. 20001 (or email gptc@aga.org). A separate completed form should be submitted for each proposed revision.

Requests for interpretations, proposed additions, and revisions to the Regulations should be directed to the Associate Administrator for Pipeline Safety, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, East Building, 2nd Floor, 1200 New Jersey Avenue, SE, Washington, D.C. 20590-0001.

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Committee Scope

The Gas Piping Technology Committee (GPTC) is an independent technical group of individuals with expertise, and concern for, gas pipeline safety and is responsible for:

- Developing and maintaining the Guide for Gas Transmission, Distribution, and Gathering Piping Systems (Guide), an American National Standards Institute (ANSI) Standard, that contains information and methods to assist a gas pipeline operator (operator) in complying with the Code of Federal Regulations "Transportation of Natural and Other Gas by Pipeline: Title 49, Subchapter D - Pipeline Safety - Part 191 - Annual Reports, Incident Reports, and Safety-Related Condition Reports; and Part 192 - Minimum Federal Safety Standards" by providing "how to" information related to the standards. Guide material is advisory in nature. Operators may use the guide material or other equally acceptable methods of compliance with the Federal Regulations.
- Developing and maintaining ANSI Technical Reports regarding the application of gas pipeline technology and operating or maintenance practices.
- Promoting the use of voluntary consensus standards.
- Petitioning the United States Department of Transportation (DOT) for changes in Federal Gas Pipeline Safety Regulations based on the technical expertise of the GPTC.
- When deemed appropriate by the Main Body, commenting on Advanced Notice of Proposed Rulemakings, Notice of Proposed Rulemakings, Final Rules, and other regulatory notices issued by DOT involving such regulations.
- Reviewing applicable National Transportation Safety Board (NTSB) reports, DOT and State Pipeline Safety Agency incident reports, and taking appropriate action including that of responding to recommendations issued to the GPTC.
- Taking such actions that are necessary and proper to further the safe application of gas pipeline technology.

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EDITORIAL NOTES FOR THE HISTORICAL RECONSTRUCTION OF PARTS 191 AND 192

Part 191 became effective on February 9, 1970. Part 192 became effective on November 12, 1970. Subsequent amendments have been issued with some adding new sections and some amending pre-existing sections.

To aid the user in reconstructing the history of a particular section, the user is advised that the complete text of Parts 191 and 192 as originally issued, plus all amendments through Amdts. 191-15 and 192-93, are contained in AGA X69804, "Historical Collection of Natural Gas Pipeline Safety Regulations." Otherwise, refer to the Federal Register website for amendments.

Additionally, to aid the user, the following tabulations of amendments are provided.

HISTORICAL RECONSTRUCTION OF PART 191

(Complete through Amdt. 191-32)

Part 191 Section	Effective Date of Original Version if other than 2/09/70	Amendments (if any)
191.1		191-5, 191-6, 191-11, 191-12, 191-15, RIN 2137-AD77, 191-21, 191-24, 191-27, 191-30
191.3		191-5, 191-10, 191-12, RIN 2137-AD43, RIN 2137-AD77, 191-21, 191-24, 191-25, 191-27, 191-29, 191-30
191.5		191-1, 191-4, 191-5, 191-8, 191-21, 191-25
191.7		191-3, 191-4, 191-5, 191-6, 191-16, RIN 2137-AD77, RIN 2137-AE29, RIN 2137-AE29 (#2), 191-21, 191-23
191.9		191-3, 191-5, 191-21
191.11		191-2, 191-5, 191-21, 191-29
[191.12]	04/04/11	191-22, 191-29
191.13		191-5
191.15		191-5, 191-21, 191-24, 191-27, 191-30, 191-32
191.17		191-5, 191-21, 191-24, 191-27, 191-30, 191-32
[191.19]		191-3,191-10, 191-21 (removed)
191.21	06/04/84	191-5, 191-13, 191-21, 191-24
191.22	01/01/11	191-21, 191-24, 191-25, 191-27, 191-28
191.23	09/29/88	191-6, 191-14, 191-24, 191-26, 191-27, 191-30, 191-31
191.25	09/29/88	191-6, 191-7, 191-8, 191-10, 191-23, 191-26
[191.27]	01/06/92	191-9, 191-14, RIN 2137-AD77, RIN 2137-AE29, RIN 2137-AE29 (#2), 191-23 (Removed)
191.29	10/01/15	191-23, 191-30
App. A	03/12/21	191-29

HISTORICAL RECORD OF AMENDMENTS TO PART 191 (Continued)

Amdt 191-	Subject	Vol FR Pg#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 191.
8	New Telephone Numbers for Reporting Incidents, Accidents and Safety-Related Conditions	54 FR 40878	10/04/89	PS-111	10/04/89 & 10/09/89	5(b) 25(a)
9	Inspection & Burial of Offshore Gas & HL Pipelines	56 FR 63764	12/05/91	PS-120	01/06/92	27
10	Program Procedures; Update and Corrections	61 FR 18512	04/26/96	PS-145	04/26/96	3, 19, 25
11	Regulatory Reinvention Initiative	61 FR 27789	06/03/96	PS-125	07/03/96	1
11	Correction	61 FR 45905	08/30/96	PS-125	07/03/96	Add Amdt. No.
12	Memorandum of Understanding with DOI*	62 FR 61692	11/19/97	RSPA-97-2096	03/19/98	1,3
12	DFR Confirmation	63 FR 12659	03/16/98	RSPA-97-2096	03/19/98	Confirmation Date
13	Periodic Updates*	63 FR 7721	02/17/98	RSPA-97-2251	05/04/98	21
13	DFR Confirmation	63 FR 38757	07/20/98	RSPA-97-2251	05/04/98	Confirmation Date
14	Metric Equivalents	63 FR 37500	07/13/98	PS-153	07/13/98	23, 27
[15]	Revision; Definition of Administrator	68 FR 11748	03/12/03	RIN 2137-AD43	03/12/03	3

HISTORICAL RECORD OF AMENDMENTS TO PART 191 (Continued)

Amdt 191-	Subject	Vol FR Pg#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 191.
16 (Shown as 15)	Producer - Operated Outer Continental Shelf Natural Gas and Hazardous Liquid Pipelines that Cross Directly Into State Waters	68 FR 46109	08/05/03	RSPA-99-6132	09/04/03	1
17 (Shown as 16)	Periodic Updates	69 FR 32886	06/14/04	RSPA-99-6106	07/14/04	7
[18]	Agency Reorganization	70 FR 11135	03/08/05	RIN 2137-AD77	03/08/05	1, 3, 7, 27
[19]	Administrative Procedures, Address Updates, and Technical Amendments*	73 FR 16562	03/28/08	RIN 2137-AE29	04/28/08	7, 27
[20]	Administrative Procedures, Address Updates, and Technical Amendments [Adopts interim final rule with modifications.]	74 FR 2889	01/16/09	RIN 2137-AE29 [Ref. as (#2)]	02/17/09	7, 27
21	Updates to Pipeline and Liquefied Natural Gas Reporting Requirements	75 FR 72878	11/26/10	PHMSA-2008-0291	01/01/11	1, 3, 5, 7, 9, 11, 15, 17, 19, 21, 22

HISTORICAL RECORD OF AMENDMENTS TO PART 191 (Continued)

Amdt 191-	Subject	Vol FR Pg#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 191.
22	Mechanical Fitting Failure Reporting Requirements	76 FR 5494	02/01/11	PHMSA-RSPA-2004-19854	04/04/11	12
23	Miscellaneous Changes to Pipeline Safety Regulations	80 FR 12762	03/11/15	PHMSA-2010-0026	10/01/15	7, 25, 27, 29
24	Safety of Underground Natural Gas Storage Facilities*	81 FR 91860	12/19/16	PHMSA-2016-0016	01/18/17	1, 3, 15, 17, 21, 22, 23
25	Operator Qualification, Cost Recovery, Accident and Incident Notification, and Other Pipeline Safety Changes	82 FR 7972	01/23/17	PHMSA-2013-0163	03/24/17	3,5,22
26	Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments	84 FR 52180	10/01/2019	PHMSA-2011-0023	07/01/2020	23, 25
27	Safety of Underground Natural Gas Storage Facilities	85 FR 8104	02/12/2020	PHMSA-2016-0016	03/13/2020	1, 3, 15, 17, 22, 23
28	Safety of Underground Natural Gas Storage Facilities; Correction	85 FR 44477	07/23/2020	PHMSA-2016-0016	07/23/2020	22
29	Gas Pipeline Regulatory Reform	86 FR 2210	01/11/2021	PHMSA-2018-0046	03/12/2021	3, 11, 12, App A

HISTORICAL RECORD OF AMENDMENTS TO PART 191 (Continued)

Amd 191-	Subject	Vol FR Pg#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 191.
30	Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments	86 FR 63266	11/15/2021	PHMSA-2011-0023	05/16/2022	1, 3, 15, 17, 23, 29
31	Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments: Response to a Petition for Reconsideration; Technical Corrections; Issuance of Limited Enforcement Discretion	87 FR 26296	05/16/22	PHMSA-2011-0023	05/04/22	23
32	Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments: Technical Corrections	87 FR 35675	05/16/22	PHMSA-2011-0023	05/16/22	15, 17
* Issued as a Direct Final Rule (DFR) or Interim Final Rule.						

HISTORICAL RECONSTRUCTION OF PART 192

(Complete through Amendment 192-134)

Part 192 Subpart	Part 192 Section	Effective Date of Original Version if other than 11/12/70	Amendments (if any)
SUBPART A – GENERAL	192.1		192-27, 192-67, 192-78, 192-81, 192-92, RIN 2137-AD77, 192-102, 192-103
	192.3		192-13, 192-27, 192-58, 192-67, 192-72 + Ext., 192-78, 192-81, 192-85, 192-89, RIN 2137-AD43, 192-93, 192-94, 192-98, RIN 2137-AD77, 192-112, 192-114, 192-120, 192-122, 192-124, 192-125, 192-126, 192-129, 192-130, 192-132, 192-132c, 192-134
	192.5		192-27, 192-56, 192-78, 192-85, 192-125, 192-127
	192.7		192-37, 192-51, 192-68, 192-78, 192-94, RIN 2137-AD77, 192-99, 192-102, 192-103, RIN 2137-AE29, RIN 2137-AE25, RIN 2137-AE29 (#2), RIN 2137-AE42, 192-112, 192-114, 192-119, 192-122, 192-124, 192-125, 192-126, 192-128, 192-132
	192.8	04/14/06	192-102, 192-129, 192-131
	192.9		192-72 + Ext., 192-95 Corr., 192-102, 192-120, 192-124, 192-125, 192-129, 192-130, 192-132, 192-134
	192.10	03/19/98	192-81, RIN 2137-AD77
	192.11	11/13/72	192-68, 192-75, 192-78, 192-119
	[192.12]		192-10, 192-36 (removed)
	192.12	01/18/17	(reassigned) 192-122, 192-126
	192.13		192-27, 192-30, 192-102, 192-129, 192-132
	192.14	12/30/77	192-30, 192-123
	192.15		
	192.16	09/13/95	192-74, 192-74A, 192-84
	[192.17]	01/01/71	192-1, 192-27A Ext., 192-38 (removed)
	192.18	10/05/22	192-125, 192-129, 192-130, 192-132
SUBPART B – MATERIALS	192.51		
	192.53		
	192.55		192-3, 192-12, 192-51, 192-68, 192-85, 192-119
	[192.57]		192-62 (removed and reserved)
	192.59		192-19, 192-58, 192-119, 192-124
	[192.61]		192-62 (removed and reserved)

	192.63		192-3, 192-31, 192-31A, 192-61, 192-61A, 192-62, 192-68, 192-76, 192-114, 192-119, 192-124
	192.65		192-12, 192-17, 192-68, 192-114, 192-119, 192-120
	192.67	01/22/19 07/01/20	192-124, 192-125 (192-124 added section and content moved to new 192.69 with 192-125)
	192.69	01/22/19	192-125 (original effective date of content is from 192-124 when original 192.67 was published)

HISTORICAL RECONSTRUCTION OF PART 192 (Continued)

Part 192 Subpart	Part 192 Section	Effective Date of Original Version if other than 11/12/70	Amendments (if any)
SUBPART C – PIPE DESIGN	192.101		
	192.103		
	192.105		192-47, 192-85
	192.107		192-78, 192-84, 192-85
	192.109		192-85
	192.111		192-27
	192.112	12/22/08	RIN 2137-AE25, 192-111, 192-119, 192-120
	192.113		192-37, 192-51, 192-62, 192-68, 192-85, 192-94, 192-119
	192.115		192-85
	[192.117]		192-37, 192-62 (removed and reserved)
	[192.119]		192-62 (removed and reserved)
	192.121		192-31, 192-78, 192-85, 192-94, 192-103, RIN 2137-AE26, 192-111, 192-114, 192-124, 192-128
	[192.123]		192-31, 192-78, 192-85, 192-93, 192-94, 192-103, RIN 2137-AE26, 192-114, 192-119, 192-124 (removed and reserved)
	192.125		192-62, 192-85
	192.127	07/01/20	192-125

HISTORICAL RECONSTRUCTION OF PART 192 (Continued)

Part 192 Subpart	Part 192 Section	Effective Date of Original Version if other than 11/12/70	Amendments (if any)
SUBPART D – DESIGN OF PIPELINE COMPONENTS	192.141		
	192.143		192-48, RIN 2137-AE09, 192-124
	192.144	08/04/83	192-45, 192-94
	192.145		192-3, 192-22, 192-37, 192-62, 192-85, 192-94, 192-103, 192-114, 192-119, 192-124
	192.147		192-62, 192-68, 192-119
	192.149		192-124
	192.150	05/12/94	192-72 + Ext., 192-85, 192-97, 192-125, 192-129
	192.151		192-85
	192.153		192-3, 192-68, 192-85, 192-119, 192-120, 192-128
	192.155		
	192.157		
	192.159		
	192.161		192-27, 192-58
	192.163		192-27, 192-37, 192-68, 192-85, 192-119
	192.165		192-119, 192-120
	192.167		192-27, 192-85
	192.169		
	192.171		
	192.173		
	192.175		192-85, 192-123
	192.177		192-58, 192-62, 192-68, 192-85, 192-119
	192.179		192-27, 192-78, 192-85, 192-130, 192-134
	192.181		
	192.183		192-85
	192.185		
	192.187		192-85
	192.189		192-76, 192-119
	192.191		192-3, 192-58, 192-114, 192-119, 192-124
	192.193		
	192.195		
	192.197		192-85, 192-93
	192.199		192-3
	192.201		192-9, 192-85
	192.203		192-78, 192-85
	192.204	01/22/19	192-124
	192.205	07/01/20	192-125

HISTORICAL RECONSTRUCTION OF PART 192 (Continued)

Part 192 Subpart	Part 192 Section	Effective Date of Original Version if other than 11/12/70	Amendments (if any)
SUBPART E – WELDING OF STEEL IN PIPELINES	192.221		
	[192.223]		192-52 (removed)
	192.225		192-18, 192-22, 192-37, 192-52, 192-94, 192-103, 192-119, 192-120, 192-123
	192.227		192-18, 192-18A, 192-22, 192-37, 192-43, 192-52, 192-75, 192-78, 192-94, 192-103, 192-119, 192-120, 192-123, 192-125
	192.229		192-18, 192-18A, 192-37, 192-78, 192-85, 192-94, 192-103, 192-119, 192-120, 192-128
	192.231		
	192.233		
	192.235		
	[192.237]		192-37, 192-52 (removed)
	[192.239]		192-37, 192-52 (removed)
	192.241		192-18, 192-18A, 192-37, 192-78, 192-85, 192-94, 192-103, 192-119, 192-120
	192.243		192-27, 192-50, 192-78, 192-120
	192.245		192-27, 192-46
SUBPART F – JOINING OF MATERIALS OTHER THAN BY WELDING	192.271		
	192.273		
	192.275		192-62
	192.277		192-62
	192.279		192-62, 192-68
	192.281		192-34, 192-58, 192-61, 192-68, 192-78, 192-114, 192-119, 192-124, 192-128
	192.283	07/01/80	192-34 + Ext., 192-34A, 192-34B, 192-68, 192-78, 192-85, 192-94, 192-103, 192-114, 192-119, 192-124, 192-128
	192.285	07/01/80	192-34 + Ext., 192-34A, 192-34B, 192-93, 192-94, 192-120, 192-124, 192-125, 192-128
	192.287	07/01/80	192-34 + Ext., 192-94

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Part 192 Subpart	Part 192 Section	Effective Date of Original Version if other than 11/12/70	Amendments (if any)
SUBPART G – GENERAL CONSTRUCTION REQUIREMENTS FOR TRANSMISSION LINES AND MAINS	192.301		
	192.303		
	192.305		192-120
	192.307		
	192.309		192-3, 192-85, 192-88
	192.311		192-93
	192.313		192-26, 192-29, 192-49, 192-85, 192-124
	192.315		192-85
	192.317		192-27, 192-78
	192.319		192-27, 192-78, 192-85, 192-132, 192-133
	192.321		192-78, 192-85, 192-93, 192-94, 192-124
	192.323		
	192.325		192-85
	192.327		192-27, 192-78, 192-85, 192-98
	192.328	12/22/08	RIN 2137-AE25
	192.329	01/22/19	192-124
SUBPART H – CUSTOMER METERS, SERVICE REGULATORS, AND SERVICE LINES	192.351		
	192.353		192-85, 192-93
	192.355		192-58
	192.357		
	192.359		192-3, 192-85
	192.361		192-75, 192-85, 192-93
	192.363		
	192.365		
	192.367		192-75, 192-124
	192.369		
	192.371		192-3, 192-85
	192.373		192-85
	192.375		192-78, 192-124
	192.376	01/22/19	192-124
	192.377		
	192.379	11/03/72	192-8
	192.381	07/22/96	192-79, 192-80, 192-85, 192-121
	192.383	02/03/98	192-83, 192-113, 192-116, 192-121
	192.385	04/17/17	192-121

HISTORICAL RECONSTRUCTION OF PART 192 (Continued)

Part 192 Subpart	Part 192 Section	Effective Date of Original Version if other than 11/12/70	Amendments (if any)
SUBPART I – REQUIREMENTS FOR CORROSION CONTROL	192.451	08/01/71	192-4, 192-27, 192-33
	192.452	12/30/77	192-30, 192-102, 192-129
	192.453	08/01/71	192-4, 192-71
	192.455	08/01/71	192-4, 192-28, 192-39, 192-78, 192-85, 192-124
	192.457	08/01/71	192-4, 192-33, 192-93
	192.459	08/01/71	192-4, 192-87
	192.461	08/01/71	192-4, 192-132
	192.463	08/01/71	192-4
	192.465	08/01/71	192-4, 192-27, 192-33, 192-35, 192-35A, 192-85, 192-93, 192-114, 192-128, 192-132
	192.467	08/01/71	192-4, 192-33
	192.469	08/01/71	192-4, 192-27
	192.471	08/01/71	192-4
	192.473	08/01/71	192-4, 192-33, 192-132, 192-133
	192.475	08/01/71	192-4, 192-33, 192-78, 192-85
	192.476	05/23/07	RIN 2137-AE09
	192.477	08/01/71	192-4, 192-33
	192.478	05/24/23	192-132
	192.479	08/01/71	192-4, 192-33, 192-93
	192.481	08/01/71	192-4, 192-27, 192-33, 192-93, 192-128
	192.483	08/01/71	192-4
	192.485	08/01/71	192-4, 192-132, 192-33, 192-78, 192-88, 192-119, 192-132
	192.487	08/01/71	192-4, 192-88
	192.489	08/01/71	192-4
	192.490	10/25/05	192-101
	192.491	08/01/71	192-4, 192-33, 192-78, 192-128
	192.493	07/01/20	192-125

HISTORICAL RECONSTRUCTION OF PART 192 (Continued)

Part 192 Subpart	Part 192 Section	Effective Date of Original Version if other than 11/12/70	Amendments (if any)
SUBPART J – TEST REQUIREMENTS	192.501		
	192.503		192-58, 192-60, 192-60A, 192-120
	192.505		192-85, 192-94, 192-120, 192-128
	192.506	07/01/20	192-125
	192.507		192-58, 192-85, 192-128
	192.509		192-58, 192-85
	192.511		192-75, 192-85
	192.513		192-77, 192-85, 192-124
	192.515		
	192.517		192-93, 192-125
SUBPART K – UPRATING	192.551		
	192.553		192-78, 192-93
	192.555		
	192.557		192-37, 192-62, 192-85
SUBPART L – OPERATIONS	192.601		
	192.603		192-27A Ext., 192-66, 192-71, 192-75, 192-118
	192.605		192-27A Ext., 192-59, 192-71, 192-71A, 192-93, 192-112
	[192.607]		192-5, 192-78 (removed and reserved)
	192.607	07/01/20	(reassigned) 192-125
	192.609		
	192.610	10/05/22	192-130, 192-134
	192.611		192-5, 192-53, 192-63, 192-78, 192-94, RIN 2137-AE25
	192.612	01/06/92	192-67, 192-85, 192-98
	192.613		192-132
	192.614	04/01/83	192-40, 192-57, 192-73, 192-78, 192-82, 192-84 + DFR Removal
	192.615		192-24, 192-71, 192-112, 192-130
	192.616	02/11/95	192-71, 192-99, 192-103, RIN 2137-AE17
	192.617		192-130
	192.619		192-3, 192-27, 192-27A, 192-30, 192-78, 192-85, 192-102, 192-103, RIN 2137-AE25, 192-125, 192-128, 192-129
	192.620	12/22/08	RIN 2137-AE25, 192-111, 192-120
	192.621		192-85
	192.623		192-75
	192.624	07/01/20	192-125, 192-127

	192.625		192-2, 192-6, 192-7, 192-14, 192-15, 192-16, 192-21, 192-58, 192-76, 192-78, 192-93
	192.627		
	192.629		
	192.631	02/01/10	192-112, 192-117, 192-123
	192.632	07/01/20	192-125
	192.634	10/05/22	192-130, 192-134
	192.635	10/05/22	192-130
	192.636	10/05/22	192-130, 192-134

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Part 192 Subpart	Part 192 Section	Effective Date of Original Version if other than 11/12/70	Amendments (if any)
SUBPART M – MAINTENANCE	192.701		
	192.703		
	102.705		192-21, 192-43, 192-78
	192.706	06/04/75	192-21, 192-43, 192-71
	192.707		192-20, 192-20A, 192-27, 192-40, 192-44, 192-73, 192-85
	192.709		192-78
	192.710	07/01/20	192-125, 192-132
	192.711		192-27B, 192-88, 192-114, 192-132
	192.712	07/01/20	192-125, 192-132
	192.713		192-27, 192-88
	192.714	05/24/23	192-132, 192-133
	192.715		192-85
	192.717		192-11, 192-27, 192-85, 192-88
	192.719		192-54
	192.720	01/22/19	192-124
	192.721		192-43, 192-78
	192.723		192-43, 192-70, 192-71, 192-94
	192.725		
	192.727		192-8, 192-27, 192-71, 192-89, RIN 2137-AD77, 192-103, RIN 2137-AE29, RIN 2137-AE29 (#2)
	[192.729]		192-71 (removed)
	192.731		192-43
	[192.733]		192-71 (removed)
	192.735		192-119
	192.736	10/18/93	192-69, 192-85
	[192.737]		192-71 (removed)
	192.739		192-43, 192-93, 192-96
	192.740	03/24/17	192-123, 192-128
	192.741		
	192.743		192-43, 192-55, 192-93, 192-96
	192.745		192-43, 192-93, 192-130
	192.747		192-43, 192-93
	192.749		192-43, 192-85
	192.750	07/01/20	192-125
	192.751		
	192.753		192-25, 192-85, 192-93
	192.755	06/01/76	192-23
	192.756	01/22/19	192-124
	[Header]		192-103 (removed)
	[192.761]		192-91, 192-95 (removed)
SUBPART N – QUALIFICATION OF PIPELINE PERSONNEL	192.801	10/26/99	192-86
	192.803	10/26/99	192-86, 192-90
	192.805	10/26/99	192-86, 192-100, 192-120, 192-125
	192.807	10/26/99	192-86

	192.809	10/26/99	192-86, 192-90, 192-100

HISTORICAL RECONSTRUCTION OF PART 192 (Continued)

Part 192 Subpart	Part 192 Section	Effective Date of Original Version if other than 11/12/70	Amendments (if any)
SUBPART O – PIPELINE INTEGRITY MANAGEMENT	Header	02/14/04	192-95, 192-103
	192.901	02/14/04	192-95
	192.903	02/14/04	192-95, 192-103, 192-119
	192.905	02/14/04	192-95
	192.907	02/14/04	192-95, 192-103
	192.909	02/14/04	192-95, 192-125
	192.911	02/14/04	192-95, 192-103, 192-132
	192.913	02/14/04	192-95, 192-103
	192.915	02/14/04	192-95
	192.917	02/14/04	192-95, 192-103, 192-125, 192-132
	192.919	02/14/04	192-95
	192.921	02/14/04	192-95, 192-103, 192-125
	192.923	02/14/04	192-95, 192-103, 192-114, 192-119, 192-132
	192.925	02/14/04	192-95, 192-103, 192-114, 192-119, 192-120
	192.927	02/14/04	192-95, 192-103, 192-132
	192.929	02/14/04	192-95, 192-103,192,132
	192.931	02/14/04	192-95, 192-103, 192-114, 192-119
	192.933	02/14/04	192-95, 192-103, 192-104, 192-119, 192-125, 192-132, 192-133
	192.935	02/14/04	192-95, 192-103, 192-114, 192-119, 192-125, 192-130, 192-132
	192.937	02/14/04	192-95, 192-103, 192-125
	192.939	02/14/04	192-95, 192-103, 192-114, 192-119, 192-125
	192.941	02/14/04	192-95, 192-132
	192.943	02/14/04	192-95
	192.945	02/14/04	192-95, 192-103, 192-115
	192.947	02/14/04	192-95
	[192.949]	02/14/04	192-95, RIN 2137-AD77, 192-103, RIN 2137-AE29, RIN 2137-AE29 (#2), 192-120, 192-125 (removed)
	192.951	02/14/04	192-95, RIN 2137-AD77, 192-103, RIN 2137-AE29, RIN 2137-AE29 (#2), 192-115
SUBPART P – GAS DISTRIBUTION PIPELINE INTEGRITY MANAGEMENT (IM)	192.1001	02/12/10	192-113, 192-116
	192.1003	02/12/10	192-113, 192-123, 192-128
	192.1005	02/12/10	192-113, 192-128
	192.1007	02/12/10	192-113, 192-116, 192-128
	[192.1009]	02/12/10	192-113, 192-116, 192-128 (removed)
	192.1011	02/12/10	192-113
	192.1013	02/12/10	192-113
	192.1015	02/12/10	192-113, 192-128

HISTORICAL RECONSTRUCTION OF PART 192 (Continued)

Part 192 Subpart	Part 192 Section	Effective Date of Original Version if other than 11/12/70	Amendments (if any)
FEDERAL APPENDICES	[App. A]		192-3, 192-10, 192-12, 192-17, 192-18, 192-19, 192-22, 192-32, 192-34 + Ext., 192-37, 192-41, 192-42, 192-51, 192-61, 192-62, 192-64, 192-65, 192-68, 192-76, 192-78, 192-84, 192-95, 192-94 (removed and reserved)
	App. B		192-3, 192-12, 192-19, 192-22, 192-32, 192-37, 192-41, 192-51, 192-61, 192-62, 192-65, 192-68, 192-76, 192-85, 192-94, 192-103, 192-114, 192-119, 192-124
	App. C		192-85, 192-94
	App. D	08/01/71	192-4
	App. E	12/15/03	192-95
	App. F	07/01/20	192-125

HISTORICAL RECORD OF AMENDMENTS TO PART 192

The following summary outlines the respective amendments and subsequent actions. Preceding documents, specifically any Notice of Proposed Rulemaking (NPRM) that may be desired for related discussion, are identified in the respective amendments.

Amdt 192-	Subject	Vol FR Pg#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 192.
-	Federal Safety Standards	35 FR 13248	08/19/70	OPS-3	11/12/70	Original Issue
1	Filing of I&M Plans	35 FR 16405	10/21/70	OPS-4	01/01/71	17
2	Odorization of Gas	35 FR 17335	11/11/70	OPS-3	11/12/70	625
3	Miscellaneous Amendments	35 FR 17659	11/17/70	OPS-3	11/12/70	55, 63, 145, 153, 191, 197, 199, 309, 359, 371, 619, App. A & B
4	Requirements for Corrosion Control	36 FR 12297	06/30/71	OPS-5	08/01/71	Subpart I, App. D
5	Extension of Time for Confirmation or Revision of MAOP	36 FR 18194	09/10/71	OPS-11	09/10/71	607, 611
6	Odorization of Gas in Transmission Lines	36 FR 25423	12/31/71	OPS-3E	01/01/72	625
7	Odorization of Gas in Transmission Lines	37 FR 17970	09/02/72	OPS-3E	09/01/72	625
8	Deactivation of Service Lines	37 FR 20694	10/03/72	OPS-10	11/03/72	379, 727
9	Modification of Pressure Relief Limitations	37 FR 20826	10/04/72	OPS-13	11/04/72	201

HISTORICAL RECORD OF AMENDMENTS TO PART 192 (Continued)

Amdt 192-	Subject	Vol FR Pg.#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 192.
10	LNG Systems	37 FR 21638	10/13/72	OPS-14	11/13/72	12, App. A
11	Mechanically Coupled Repair Sleeves	37 FR 21816	10/14/72	OPS-20	11/14/72	717
12	Qualification for Pipe	38 FR 4760	02/22/73	OPS-15	03/22/73	55, 65, App. A & B
13	Definition of Service Line	38 FR 9083	04/10/73	OPS-9	05/10/73	3
14	Odorization of Gas in Transmission Lines	38 FR 14943	06/07/73	OPS-3E	06/01/73	625
15	Odorization of Gas in Transmission Lines	38 FR 35471	12/28/73	OPS-3E	01/01/74	625
16	Odorization of Gas in Transmission Lines	39 FR 45253	12/31/74	OPS-3E	01/01/75	625
17	Qualification of Pipe Transported by Railroad	40 FR 6345	02/11/75	OPS-26	02/25/75	65, App. A
17	Correction	40 FR 8188	02/26/75	OPS-26	02/26/75	App. A
17	Correction	40 FR 24361	06/06/75	OPS-26	06/06/75	65
18	Welding Requirements	40 FR 10181	03/05/75	OPS-25	03/20/75	225, 227, 229, 241, App. A
18A	Correction	40 FR 27222	06/27/75	OPS-25A	07/01/75	227, 229, 241
19	Qualification For Use of Plastic Pipe	40 FR 10471	03/06/75	OPS-27	03/21/75	59, App. A & B

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Amdt 192-	Subject	Vol FR Pg.#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 192.
20	Line Markers For Mains & Transmission Lines	40 FR 13502	03/27/75	OPS-18	04/21/75	707
20A	- - -	41 FR 56807	12/30/76	OPS-18	12/31/76	707
21	Odorization of Gas in Transmission Lines	40 FR 20279	05/09/75	OPS-241	06/04/75	625, 705, 706
22	Incorporation by Reference	41 FR 13589	03/31/76	OPSO-34	07/01/76	145, 225, 227, App. A & B
23	Protecting Cast Iron Pipelines	41 FR 13588	03/31/76	OPS-33	06/01/76	755
24	Emergency Plans	41 FR 13586	03/31/76	OPS-32	10/01/76	615
25	Caulked Bell & Spigot Joints	41 FR 23679	06/11/76	OPSO-36	07/04/76	753
26	Bending Limitations	41 FR 26016	06/24/76	OPS-23	07/01/76	313
27	Offshore Pipeline Facilities	41 FR 34598	08/16/76	OPS-30	11/01/76	1, 3, 5, 13, 161, 163, 243, 245, 451, 465, 469, 481, 707, 713, 717, 727
27	Offshore Pipeline Facilities	41 FR 34598	08/16/76	OPS-30	08/01/77	111, 167, 179, 317, 319, 327, 619
27	Correction	41 FR 39752	09/16/76	OPS-30	11/01/76	707
27A	Time Extension	41 FR 47252	10/28/76	OPS-30	10/28/76	619

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Amdt 192-	Subject	Vol FR Pg#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 192.
27A	- - -	41 FR 47252	10/28/76	OPS-30	03/16/77	17, 603(b), 605
27B	- - -	45 FR 3272	01/17/80	OPS-30	01/17/80	711
28	Corrosion Control for Metal Alloy Fittings in Plastic Pipelines	42 FR 35653	07/11/77	OPSO-37	08/12/77	455
29	Longitudinal Seams in Pipe Bends	42 FR 42865	08/25/77	OPSO-38	10/03/77 & 11/03/77	313
29	Correction	42 FR 60148	11/25/77	OPSO-38	11/03/77	313
30	Conversion of Existing Pipelines to Gas Service	42 FR 60146	11/25/77	OPSO 77-3	12/30/77	13, 14, 452, 619
31	Design of Plastic Pipelines	43 FR 13880	04/03/78	OPSO-42	05/18/78	63, 121, 123
31A	Time Extension	43 FR 21462	05/18/78	OPSO-42	05/18/78	63
31	Correction	43 FR 43308	09/25/78	OPSO-42	09/03/78	121
32	Qualification and Design of Steel Pipe	43 FR 18553	05/01/78	77-10	06/01/78	App. A & B
32	Correction	43 FR 27540	06/26/78	77-10	06/26/78	App. A
33	Corrosion Control Requirements	43 FR 39389	09/05/78	PS-50	09/05/78	451, 457, 465, 467, 473, 475, 477, 479, 481, 485, 491
34	Joining of Plastic Pipe	44 FR 42968	07/23/79	PS-54	01/01/80	281, 283, 285, 287, App. A

HISTORICAL RECORD OF AMENDMENTS TO PART 192 (Continued)

Amdt 192-	Subject	Vol FR Pg#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 192.
34	Time Extension	44 FR 50841	08/30/79	PS-54	08/30/79	281, 283, 285, 287, App. A
34	Time Extension	44 FR 57100	10/04/79	PS-54	07/01/80	281, 283, 285, 287, App. A
34A	- - -	45 FR 9931	02/14/80	PS-54	07/01/80	283, 285
34B	- - -	46 FR 39	01/02/81	PS-54	01/02/81	283, 285
34 (PS-54)	Correction	47 FR 32720	07/29/82	PS-54	07/29/82	283
34 (PS-54)	Correction	47 FR 49973	11/04/82	PS-54	11/04/82	283
35	Cathodically Protected Transmission Lines	44 FR 75384	12/20/79	PS-52	12/20/79	465
35A	Correction	45 FR 23441	04/07/80	PS-52	04/07/80	465
36	LNG Facilities	45 FR 70390	10/23/80	OPSO-46	03/15/80	12
37	Incorporation by Reference	46 FR 10157	02/02/81	PS-65	03/04/81	7, 113, 117, 145, 163, 225, 227, 229, 237, 239, 241, 557, App. A & B
38	Reports of Leaks & Federal Safety Standards	46 FR 37250	07/20/81	PS-68	07/20/81	17

HISTORICAL RECORD OF AMENDMENTS TO PART 192 (Continued)

Amdt 192-	Subject	Vol FR Pg#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 192.
39	Metal Alloy Fittings in Plastic Pipelines	47 FR 9842	03/08/82	OPSO-37	04/07/82	455(f)
40	Damage Prevention Program	47 FR 13818	04/01/82	PS-59	04/01/83	614, 707
41	Incorporation by Reference	47 FR 41381	09/20/82	PS-65	10/20/82	App. A & B
42	Incorporation by Reference	47 FR 44263	10/07/82	PS-65	10/07/82	App. A
43	Inspection and Test Intervals	47 FR 46850	10/21/82	PS-73	11/22/82	227, 705, 706, 721, 723, 731, 739, 743, 745, 747, 749
44	Line Marking at Navigable Waterways	48 FR 25206	06/06/83	PS-69	07/06/83	707
45	Qualification of Metallic Components	48 FR 30637	07/05/83	PS-64	08/04/83	144
46	Repair or Removal of Girth Weld Defects	48 FR 48669	10/20/83	PS-74	11/21/83	245
47	Temperature Limits on Cold Expanded Steel Pipe	49 FR 7567	03/01/84	PS-58	04/02/84	105
48	Design of Pipeline Components	49 FR 19823	05/10/84	PS-78	06/11/84	143
49	Ovality of Field Bends in Steel Pipe	50 FR 13224	04/03/85	PS-81	05/03/85	313

HISTORICAL RECORD OF AMENDMENTS TO PART 192 (Continued)

Amdt 192-	Subject	Vol FR Pg#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 192.
50	Nondestructive Testing	50 FR 37191	09/12/85	PS-83	10/15/85	243
51	Updating Steel Line Pipe Specifications	51 FR 15333	04/23/86	PS-86	05/23/86	7, 55, 113, App. A & B
52	Welding Requirements	51 FR 20294	06/04/86	PS-87	07/07/86	223, 225, 227, 237, 239
53	Period for Confirmation or Revision of MAOP	51 FR 34987	10/01/86	PS-90	10/31/86	611
54	Exceptions From Non-Destructive Testing of Welds in Transmission Line Repair	51 FR 41634	11/18/86	PS-92	12/18/86	719
55	Interval for Review and Calculation of Relief Device Capacity	51 FR 41633	11/18/86	PS-91	12/18/86	743
56	Confirmation or Revision of MAOP Near Certain Occupied Buildings and Outside Areas	52 FR 32924	09/01/87	PS-84	10/01/87	5
57	Damage Prevention Programs	52 FR 32798	08/31/87	PS-88	09/30/87	614
58	Miscellaneous Amendments	53 FR 1633	01/21/88	PS-99	02/22/88	3, 59, 161, 177, 191, 281, 355, 503, 507, 509, 625

HISTORICAL RECORD OF AMENDMENTS TO PART 192 (Continued)

Amdt 192-	Subject	Vol FR Pg#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 192.
59	Reporting Unsafe Conditions on Gas & HL Pipelines and LNG Facilities	53 FR 24942	07/01/88	PS-96	09/29/88	605
59	Correction	53 FR 26560	07/13/88	PS-96	09/29/88	605
60	Exception from Pressure Testing Non-Welded Tie-In Joints	53 FR 36028	09/16/88	PS-98	10/17/88	503
60A	- - -	54 FR 5484	02/03/89	PS-98	10/17/88	503
61	Incorporation by Reference of ASTM D-2513	53 FR 36793	09/22/88	PS-103	10/24/88	63, 281, App. A & B
61A	- - -	54 FR 32641	08/09/89	PS-103	08/09/89	63
62	Referenced Standards Deletion Affecting Iron, Steel, and Copper Pipe and Other Materials	54 FR 5625	02/06/89	PS-95	03/08/89	57, 61, 63, 113, 117, 119, 125, 145, 147, 177, 275, 277, 279, 557, App. A & B
62	Correction	54 FR 32344	08/07/89	PS-95	08/07/89	App. A
63 (shown as 60A)	Confirmation or Revision of MAOP; Alternative Method	54 FR 24173	06/06/89	PS-97	07/06/89	611
63 (PS-97)	Correction	54 FR 25716	06/19/89	PS-97	06/19/89	Corrected Amdt. Number

HISTORICAL RECORD OF AMENDMENTS TO PART 192 (Continued)

Amdt 192-	Subject	Vol FR Pg#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 192.
64	Incorporation by Reference of Portions of API 1104, 17th Ed., 1988	54 FR 27881	07/03/89	PS-108	08/02/89	App. A
65	Pipeline Safety, Steel Pipe	54 FR 32344	08/07/89	PS-110	09/06/89	App. A & B
66	Amendment of an Operator's Plans or Procedures	56 FR 31087	07/09/91	PS-114	08/08/91	603(c)
67	Inspection and Burial of Offshore Gas and HL Pipelines	56 FR 63764	12/05/91	PS-120	01/06/92	1, 3, 612
68 (PS-131)	Update of Standards Incorporated by Reference	58 FR 14519	03/18/93	PS-131	04/19/93	7, 11, 55, 63, 65, 113, 147, 153, 163, 177, 279, 281, 283, App. A & B
68	Correction	58 FR 45268	08/27/93	PS-131	04/19/93	Add Amdt. Number, 153, App. A
69	Gas Detection & Monitoring in Compressor Station Buildings	58 FR 48460	09/16/93	PS-100	10/18/93	736
70	Leakage Surveys on Distribution Lines Located Outside Business Districts	58 FR 54524	10/22/93	PS-123	11/22/93	723

HISTORICAL RECORD OF AMENDMENTS TO PART 192 (Continued)

Amdt 192-	Subject	Vol FR Pg#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 192.
71	O & M Procedures for Pipelines	59 FR 6579	02/11/94	PS-113	03/14/94	605(b)(9)
71	- - -	59 FR 6579	02/11/94	PS-113	02/11/95	453, 603, 605, 615(d)-Redesignated, 616, 706, 723, 727, 729, 733, 737
71A	- - -	60 FR 14379	03/17/95	PS-113	04/17/95	605
72	Passage of Instrumented Internal Inspection Devices	59 FR 17275	04/12/94	PS-126	05/12/94	3, 9, 150
72	Time Extension	59 FR 49896	09/30/94	PS-126, Notice 2	09/30/94	3, 9, 150
72	Correction and Time Extension	59 FR 52863	10/19/94	PS-126, Notice 2	10/19/94	Edit. Corr.
72	Time Extension	60 FR 7133	02/07/95	PS-126, Notice 3	01/30/95	3, 9, 150
73	Excavation Damage Prevention Program	60 FR 14646	03/20/95	PS-101	04/19/95	614, 707
74 (shown as 3)	Customer-Owned Service Lines	60 FR 41821	08/14/95	PS-135	09/13/95	16
74	Correction	60 FR 43028	08/18/95	PS-135	09/13/95	Corr. Amdt. No.
74A	- - -	60 FR 63450	12/11/95	PS-135	01/10/96	16(a)

HISTORICAL RECORD OF AMENDMENTS TO PART 192 (Continued)

Amdt 192-	Subject	Vol FR Pg#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 192.
75 (shown as 74)	Program Procedures; Update and Corrections	61 FR 18512	04/26/96	PS-145	04/26/96	11, 227, 361, 367, 511, 603, 623
75	Correction	61 FR 38403	07/24/96	PS-145	07/24/96	Corr. Amdt. No.
76	Periodic Updates	61 FR 26121	05/24/96	PS-143	06/24/96	63, 189, 625, App.A
76	Correction	61 FR 36825	07/15/96	PS-143	08/14/96	Add Amdt. No., 63, App. B
77	Regulatory Reinvention Initiative	61 FR 27789	06/03/96	PS-125	07/03/96	513
77	Correction	61 FR 45905	08/30/96	PS-125	07/03/96	Add Amdt. No., 513
78	Regulatory Review	61 FR 28770	06/06/96	PS-124	07/08/96	1, 3, 5, 7, 11, 107, 121, 123, 179, 203, 227, 229, 241, 243, 281, 283, 317, 319, 321, 327, 375, 455, 475, 485, 491, 553, 607, 611, 614, 619, 625, 705, 709, 721, App. A
78	Correction	61 FR 30824	06/18/96	PS-124	07/08/96	Corr. Amdt. No.
78	Correction	61 FR 35139	07/05/96	PS-124	07/08/96	5
78	Correction	61 FR 41019	08/07/96	PS-124	08/07/96	App. A

HISTORICAL RECORD OF AMENDMENTS TO PART 192 (Continued)

Amdt 192-	Subject	Vol FR Pg#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 192.
79	Excess Flow Valve - Performance Stds.	61 FR 31449	06/20/96	PS-118	07/22/96	381
80	Excess Flow Valve - Performance Stds.	62 FR 2618	01/17/97	PS-118	02/18/97	381
81	Memorandum of Understanding with DOI*	62 FR 61692	11/19/97	RSPA 97-2096	03/19/98	1, 3, 10
81	DFR Confirmation	63 FR 12659	03/16/98	RSPA 97-2096	03/19/98	Confirmation Date
82	Participation in One-Call Systems	62 FR 61695	11/19/97	PS-101A	05/18/98	614
83	Excess Flow Valve – Customer Notification	63 FR 5464	02/03/98	PS-118A	02/03/98	383
83	Correction	63 FR 20134	04/23/98	PS-118A	04/23/98	Corr. Amdt. No. & Metric Units
84	Periodic Updates*	63 FR 7721	02/17/98	RSPA 97-2251	05/04/98	16, 107, 614, App. A
84	Removal of DFR Amendment & DFR Confirmation	63 FR 38757	07/20/98	RSPA 97-2251	07/20/98 05/04/98	614(c)(5) Confirmation Date
84	Correction to DFR	63 FR 38758	07/20/98	RSPA 97-2251	07/20/98	Corr. Amdt. No. & ASTM Ref. in App. A

HISTORICAL RECORD OF AMENDMENTS TO PART 192 (Continued)

Amdt 192-	Subject	Vol FR Pg#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 192.
85	Metric Equivalents	63 FR 37500	07/13/98	PS-153	07/13/98	3, 5, 55, 105, 107, 109, 113, 115, 121, 123, 125, 145, 150, 151, 153, 163, 167, 175, 177, 179, 183, 187, 197, 201, 203, 229, 241, 283, 309, 313, 315, 319, 321, 325, 327, 353, 359, 361, 371, 373, 381, 455, 465, 475, 505, 507, 509, 511, 513, 557, 612, 619, 621, 707, 715, 717, 736, 749, 753, App. B & C
86	Qualification of Pipeline Personnel	64 FR 46853	08/27/99	RSPA 98-3783	10/26/99	801, 803, 805, 807, 809
87	Determining the Extent of Corrosion on Gas Pipelines	64 FR 56978	10/22/99	PS-107	11/22/99	459
88	Gas Pipeline Repair	64 FR 69660	12/14/99	RSPA 98-4733	01/13/00	309, 485, 487, 711, 713, 717
89	Underwater Abandoned Pipeline Facilities	65 FR 54440	09/08/00	RSPA 97-2094	10/10/00	3, 727
89	Correction	65 FR 57861	09/26/00	RSPA 97-2094	10/10/00	727

HISTORICAL RECORD OF AMENDMENTS TO PART 192 (Continued)

Amdt 192-	Subject	Vol FR Pg#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 192.
90	Qualification of Pipeline Personnel, Correction	66 FR 43523	08/20/01	RSPA 98-3783	08/20/2001	803, 809
91	High Consequence Areas for Gas Transmission Pipelines	67 FR 50824	08/06/02	RSPA 00-7666	09/05/02	761
91	Correction	69 FR 21975	04/23/04	RSPA 00-7666	04/23/04	Corr. Amdt. No.
[No Amdt No.]	Revision; Definition of Administrator	68 FR 11748	03/12/03	RIN 2137-AD43	03/12/03	3
92	Producer - Operated Outer Continental Shelf Natural Gas and Hazardous Liquid Pipelines that Cross Directly Into State Waters	68 FR 46109	08/05/03	RSPA 99-6132	09/04/03	1
93	Further Regulatory Review	68 FR 53895	09/15/03	RSPA 02-13208	10/15/03	3, 123, 197, 285, 311, 321, 353, 361, 457, 465, 479, 481, 517, 553, 605, 625, 739, 743, 745, 747, 753
94	Periodic Update	69 FR 32886	06/14/04	RSPA 99-6106	07/14/04	3, 7, 113, 121, 123, 144, 145, 225, 227, 229, 241, 283, 285, 287, 321, 505, 611, 723, App. A, B, & C

HISTORICAL RECORD OF AMENDMENTS TO PART 192 (Continued)

Amdt 192-	Subject	Vol FR Pg#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 192.
94	Correction	69 FR 54591	09/09/04	RSPA 99-6106	07/14/04	3, 7, 123, 283, 505, 723, App. B
94	DFR* [Correction]	70 FR 3147	01/21/05	RSPA 99-6106	05/06/05	3
95	Pipeline Integrity Management	68 FR 69778	12/15/03	RSPA 00-7666	01/14/04	901, 903, 905, 907, 909, 911, 913, 915, 917, 919, 921, 923, 925, 927, 929, 931, 933, 935, 937, 939, 941, 943, 945, 947, 949, 951, App. A & E
95	Correction	69 FR 2307	01/15/04	RSPA 00-7666	02/14/04	Correct Effective Date
95	Correction & Petition for Reconsideration	69 FR 18228	04/06/04	RSPA 00-7666	04/06/04	9, 903, 909, 911, 913, 917, 921, 925, 927, 929, 933, 935, 937, 939, 941, 943, 945, 947, App. A & E
95	Correction	69 FR 29903	05/26/04	RSPA 00-7666	05/26/04	903, 925, 935, App. E
96	Pressure Limiting and Regulating Stations*	69 FR 27861	05/17/04	RSPA 02-13208	09/14/04	739, 743
96	DFR Confirmation	69 FR 54248	09/08/04	RSPA 02-13208	10/08/04	739, 743

HISTORICAL RECORD OF AMENDMENTS TO PART 192 (Continued)

Amdt 192-	Subject	Vol FR Pg#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 192.
97	Passage of Internal Inspection Devices	69 FR 36024	06/28/04	RSPA-RSPA-03-16330	07/28/04	150
98	Periodic Underwater Inspections	69 FR 48400	08/10/04	RSPA-RSPA-97-3001	09/09/04	3, 327, 612
[No Amdt No.]	Agency Reorganization	70 FR 11135	03/08/05	RIN 2137-AD77	03/08/05	1, 3, 7, 10, 727, 949, 951
99 (Shown as 100)	Pipeline Operator Public Awareness Program	70 FR 28833	05/19/05	RSPA-03-15852	06/20/05	7, 616
99	Correction	70 FR 35041	06/16/05	RSPA-03-15852	06/20/05	Corr. Amdt. No., 616
100	Operator Qualifications; Statutory Changes*	70 FR 10332	03/03/05	RSPA-RSPA-03-15734	07/01/05	805, 809
100	DFR Confirmation	70 FR 34693	06/15/05	RSPA-RSPA-03-15734	07/15/05	805, 809
101	Standards for Direct Assessment of Gas and Hazardous Liquid Pipelines	70 FR 61571	10/25/05	RSPA-04-16855	11/25/05	490
102	Gas Gathering Line Definition	71 FR 13289	03/15/06	RSPA-98-4868	04/14/06	1, 7, 8, 9, 13, 452, 619

HISTORICAL RECORD OF AMENDMENTS TO PART 192 (Continued)

Amdt 192-	Subject	Vol FR Pg#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 192.
103	Update of Regulatory References to Technical Standards	71 FR 33402	06/09/06	RIN 2138-AD68	07/10/06	7, 121, 123, 145, 225, 227, 229, 241, 283, 616, 619, Header before 761, Subpart O Header, 903, 907, 911, 913, 917, 921, 923, 925, 927, 929, 931, 933, 935, 937, 939, 945, App. B
103 [Amended]	Update of Regulatory References to Technical Standards [Amending that published [06/09/06]	72 FR 4655	02/01/07	RIN 2137-AD68	03/05/07	1, 7, 227, 727, 903, 949, 951
[No Amdt No.]	Design and Construction Standards to Reduce Internal Corrosion in Gas Transmission Pipelines	72 FR 20055	04/23/07	RIN 2137-AE09	05/23/07	143, 476
104	Integrity Management Program Modifications and Clarifications	72 FR 39012	07/17/07	RIN 2137-AE07	08/16/07	933

HISTORICAL RECORD OF AMENDMENTS TO PART 192 (Continued)

Amdt 192-	Subject	Vol FR Pg#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 192.
[105]	Applicability of Public Awareness Regulations to Certain Gas Distribution Operators	72 FR 70808	12/13/07	RIN 2137-AE17	01/14/08	616
[106]	Administrative Procedures, Address Updates, and Technical Amendments*	73 FR 16562	03/28/08	RIN 2137-AE29	04/28/08	7, 727, 949, 951
[107]	Standards for Increasing the Maximum Allowable Operating Pressure for Gas Transmission Pipelines	73 FR 62148	10/17/08	RIN 2137-AE25	11/17/08	7, 112, 328, 611, 619, 620
[107 Stay]	Standards for Increasing the Maximum Allowable Operating Pressure for Gas Transmission Pipelines	73 FR 72737	12/01/08	RIN 2137-AE25 [Ref. as "Eff. date stayed"]	12/22/08	112, 328, 611, 619, 620
[108]	Polyamide-11 (PA-11) Plastic Pipe Design Pressures	73 FR 79002	12/24/08	RIN 2137-AE26	01/23/09	121, 123

HISTORICAL RECORD OF AMENDMENTS TO PART 192 (Continued)

Amdt 192-	Subject	Vol FR Pg#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 192.
[109]	Administrative Procedures, Address Updates, and Technical Amendments [Adopts interim final rule with modifications.]	74 FR 2889	01/16/09	RIN 2137-AE29 [Ref. as (#2)]	02/17/09	7, 727, 949, 951
[110]	Incorporated by Reference Update: American Petroleum Institute (API) Standards 5L and 1104*	74 FR 17099	04/14/09	RIN 2137-AE42	04/14/09	7
[110]	DFR Confirmation	74 FR 30476	06/26/09	RIN 2137-AE42	04/14/09	7
111	Editorial Amendments to the Pipeline Safety Regulations	74 FR 62503	11/30/09	PHMSA-2009-0265	01/29/10	112, 121, 620
112	Control Room Management / Human Factors	74 FR 63310	12/03/09	PHMSA-2007-27954	02/01/10	3, 7, 605, 615, 631
112	Correction	75 FR 5536	02/03/10	PHMSA-2007-27954	Applicable 02/01/10	631
113	Integrity Management Program for Gas Distribution Pipelines	74 FR 63906	12/04/09	PHMSA-RSPA-2004-19854	02/02/10	383, 1001, 1003, 1005, 1007, 1009, 1011, 1013, 1015

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Amdt 192-	Subject	Vol FR Pg#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 192.
113	Correction	75 FR 5244	02/02/10	PHMSA-RSPA-2004-19854	02/12/10	383, 1001, 1003, 1005, 1007, 1009, 1011, 1013, 1015
114	Periodic Updates of Regulatory References to Technical Standards and Miscellaneous Edits	75 FR 48593	08/11/10	PHMSA-2008-0301	10/01/10	3, 7, 63, 65, 121, 123, 145, 191, 281, 283, 465, 711, 923, 925, 931, 935, 939, App.B
115	Updates to Pipeline and Liquefied Natural Gas Reporting Requirements	75 FR 72878	11/26/10	PHMSA-2008-0291	01/01/11	945, 951
116	Mechanical Fitting Failure Reporting Requirements	76 FR 5494	02/01/11	PHMSA-RSPA-2004-19854	04/04/11	383, 1001, 1007, 1009
117	Control Room Management/Human Factors	76 FR 35130	06/16/11	PHMSA-2007-27954	08/15/11	631
118	Administrative Procedures; Update and Technical Corrections	78 FR 58897	09/25/13	PHMSA-2012-0102	10/25/13	603

HISTORICAL RECORD OF AMENDMENTS TO PART 192 (Continued)

Amdt 192-	Subject	Vol FR Pg#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 192.
119	Periodic Updates of Regulatory References to Technical Standards and Miscellaneous Amendments	80 FR 168	01/05/15	PHMSA-2011-0337	03/06/15	7, 11, 55, 59, 63, 65, 112, 113, 123, 145, 147, 153, 163, 165, 177, 189, 191, 225, 227, 229, 241, 281, 283, 485, 735, 903, 923, 925, 931, 933, 935, 939, App. B
119	Correction	80 FR 46847	08/06/15	PHMSA-2011-0337	08/06/15	11, 55, 153, 191, 735, 923, 933, App. B
120	Miscellaneous Changes to Pipeline Safety Regulations	80 FR 12762	03/11/15	PHMSA-2010-0026	10/01/15	3, 9, 65, 112, 153, 165, 225, 227, 229, 241, 243, 285, 305, 503, 505, 620, 805, 925, 949
120	Response to Petitions for Reconsideration	80 FR 58633	09/30/15	PHMSA-2010-0026	Delayed indefinitely on 09/30/15	305
121	Expanding the Use of Excess Flow Valves	81 FR 70987	10/14/16	PHMSA-2011-0009	04/14/17	381, 383, 385
121	Correction	81 FR 72739	10/21/16	PHMSA-2011-0009	04/14/17	383
122	Safety of Underground Natural Gas Storage Facilities*	81 FR 91860	12/19/16	PHMSA-2016-0016	01/18/17	3, 7, 12

* Issued as a Direct Final Rule (DFR) or Interim Final Rule.

HISTORICAL RECORD OF AMENDMENTS TO PART 192 (Continued)

Amdt 192-	Subject	Vol FR Pg#	Published Date	Docket or RIN No.	Effective Date	Affected Sections 192.
123	Operator Qualification, Cost Recovery, Accident and Incident Notification, and Other Pipeline Safety Changes	82 FR 7972	01/23/17	PHMSA-2013-0163	03/24/17	14, 175, 225, 227, 631, 740, 1003
124	Plastic Pipe Rule	83 FR 58694	11/20/18	PHMSA-2014-0098	01/22/19	3, 7, 9, 59, 63, 67, 121, 123, 143, 145, 149, 191, 204, 281, 283, 285, 313, 321, 329, 367, 375, 376, 455, 513, 720, 756, App B
125	Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments	84 FR 52180	10/01/2019	PHMSA-2011-0023	07/1/2020	3, 5, 7, 9, 18, 67, 127, 150, 205, 227, 285, 493, 506, 517, 607, 619, 624, 632, 710, 712, 750, 805, 909, 917, 921, 933, 935, 937, 939, 949, App F
126	Safety of Underground Natural Gas Storage Facilities	85 FR 8104	02/12/2020	PHMSA-2016-0016	03/13/2020	3, 7, 12
127	MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments: Response to a Joint Petition for Reconsideration	85 FR 40132	07/06/2020	PHMSA-2011-0023	07/01/2020	5, 624

Amdt 192-	Subject	Vol FR Pg#	Published Date	Docket or RIN #	Effective Date	Affected Sections 192.
128	Gas Pipeline Regulatory Reform	86 FR 2210	01/11/2021	PHMSA-2018-0046	03/12/2021	7, 121, 153, 229, 281, 283, 285, 465, 481, 491, 505, 507, 619, 740, 1003, 1005, 1007, 1009, 1015, App B
129	Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments	86 FR 63266	11/15/2021	PHMSA-2011-0023	05/16/2022	3, 8, 9, 13, 18, 150, 452, 619
130	Requirement of Valve Installation and Minimum Rupture Detection Standards	87 FR 20940	04/08/22	PHMSA-2013-0255	10/05/22	3, 9, 18, 179, 610, 615, 617, 634, 635, 636, 745, 935
131	Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other	87 FR 26296	05/04/22	PHMSA-2011-0023	05/16/22	8

	Related Amendments: Response to a Petition for Reconsideration; Technical Corrections; Issuance of Limited Enforcement Discretion					
132	Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments	87 FR 52224	08/24/22	PHMSA-2011-0023	05/24/23	3, 7, 9, 13, 18, 319, 461, 465, 473, 478, 485, 613, 710, 711, 712, 714, 911, 917, 923, 927, 929, 933, 935, 941
132c	Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments	87 FR 64384	10/25/22	PHMSA-2011-0023	05/24/23	3

133	Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments: Technical Corrections; Response to Petitions for Reconsideration	88 FR 24708	04/24/23	PHMSA-2011-0023	05/24/23	319, 473, 714, 933
134	Requirement of Valve Installation and Minimum Rupture Detection Standards: Technical Corrections	88 FR 50056	08/01/23	PHMSA-2013-0255	08/01/23	3, 9, 179, 610, 634, 636

§191.9

Distribution system: Incident report.

[Effective Date: 01/01/11]

(a) Except as provided in paragraph(c) of this section, each operator of a distribution pipeline system shall submit Department of Transportation Form RSPA F 7100.1 as soon as practicable but not more than 30 days after detection of an incident required to be reported under §191.5.

(b) 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.

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

[Amdt. 191-3, 46 FR 37250, July 20, 1981; Amdt. 191-5, 49 FR 18956, May 3, 1984; Amdt. 191-21, 75 FR 72878, Nov. 26, 2010]

GUIDE MATERIAL

(a) See Guide Material Appendix G-191-2 for an index of PHMSA reporting forms used for federal reporting. Report forms and instructions can be downloaded from the PHMSA-OPS website at www.phmsa.dot.gov/forms/pipeline-forms.
(b) Additional state reporting requirements may exist for intrastate facilities.
(c) Section 192.605 requires operators to have procedures to gather data for the reporting of incidents required by §191.5. See 2.3 and 5 of the guide material under §192.605 and the guide material under §192.617.
(d) Distribution operators with Type R gathering pipelines will have to submit separate incident reports for the Type R pipelines.

§191.11

Distribution system: Annual report.

[Effective Date: 03/12/21]

(a) *General*. Except as provided in paragraph (b) of this section, each operator of a distribution pipeline system must submit an annual report for that system on DOT Form PHMSA F7100.1–1. This report must be submitted each year, not later than March 15, for the preceding calendar 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 pipeine or a gathering line as determined in §192.8.

[Amdt. 191-2, 37 FR 1172, Jan. 26, 1972; Amdt. 191-5, 49 FR 18956, May 3, 1984; Amdt. 191-21, 75 FR 72878, Nov. 26, 2010]

GUIDE MATERIAL

(a) See Guide Material Appendix G-191-2 for an index of PHMSA reporting forms used for federal reporting. Report forms and instructions can be downloaded from the PHMSA-OPS website www.phmsa.dot.gov/forms/pipeline-forms.
(b) Additional state reporting requirements may exist for intrastate facilities.
(c) Distribution operators with Type R gathering pipelines will have to submit separate annual reports for the Type R pipelines.

§191.12 [Reserved]

[Effective Date: 03/12/21]

§191.13

Distribution systems reporting transmission pipelines; transmission or gathering systems reporting distribution pipelines.

[Effective Date: 06/04/84]

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.

[Amdt. 191-5, 49 FR 18956, May 3, 1984]

GUIDE MATERIAL

(a) See §191.3 for definitions of regulated onshore gathering and reporting-regulated gathering. See §192.3 for definitions of *Distribution line, Gathering line, and Transmission lines.*
(b) Additional state reporting requirements may exist for intrastate facilities, but federal reports for gathering lines are based on the definitions found in §192.8.
(c) See Guide Material Appendix G-191-2 for an index of PHMSA reporting forms.

§191.15

Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas storage facilities: Incident report.

[Effective Date: 01/18/17]

***(a) Pipeline systems*— (1) *Transmission or regulated onshore gathering*. Each operator of a transmission pipeline system or a regulated onshore gathering pipeline system must submit Department of Transportation (DOT) Form PHMSA F 7100.2 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) *LNG*. Each operator of a liquefied natural gas plant or facility must submit DOT Form PHMSA F 7100.3 as soon as practicable but not more than 30 days after detection of an incident required to be reported under §191.5 of this part.

(c) *Underground natural gas storage facility.* Each operator of an underground natural gas storage facility must submit 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.

(d) *Supplemental report*. Where additional related information is obtained after a report is submitted under paragraph (a), (b) or (c) of this section, the operator must make a supplemental report as soon as practicable with a clear reference by date to the original report.

[Amdt. 191-5, 49 FR 18956, May 3, 1984; Amdt. 191-21, 75 FR 72878, Nov. 26, 2010; Amdt. 191-24, 81 FR 91871, Dec. 19, 2016; Amdt. 191-30, 86 FR 63294 Nov. 15, 2021]

GUIDE MATERIAL

(a) See Guide Material Appendix G-191-2 for an index of PHMSA reporting forms, used for federal reporting. Report forms and instructions can be downloaded from the PHMSA-OPS website at www.phmsa.dot.gov/forms/pipeline-forms.
(b) Additional state reporting requirements may exist for intrastate facilities.
(c) Section 192.605 requires operators to have procedures to gather data for the reporting of incidents required by §191.5. See 2.3 and 5 of the guide material under §192.605 and the guide material under §192.617.
(d) Transmission, Type A gathering, Type B gathering, and Type C gathering operators who also have Type R gathering pipelines will have to submit separate incident reports for the Type R pipelines (§191.15).

§191.17

Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas storage facilities: Annual report.

[Effective Date: 01/18/17]

(a) *Pipeline systems*– (1) *Transmission or regulated onshore gathering*. Each operator of a transmission or a regulated onshore gathering pipeline system must submit an annual report for that system on DOT Form PHMSA 7100.2–1. This report must be submitted each year, not later than March 15, for the preceding calendar 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 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, except that for the 2010 reporting year the report must be submitted by June 15, 2011.

(c) *Underground natural gas storage facility.* Each operator of a UNGSF must submit an annual report through DOT Form PHMSA 7100.4-1. This report must be submitted each year, no later than March 15, for the preceding calendar year.

[75 FR 72905, Nov. 26, 2010, as amended by Amdt. 191-24, 81 FR 91871, Dec. 19, 2016; Amdt. 191-27, 85 FR 8125, Feb. 12, 2020; Amdt. 191-30, 86 FR 63295, Nov. 15, 2021; Amdt. 191-32, 87 FR 35677. June 13, 2022]

GUIDE MATERIAL

(a) See Guide Material Appendix G-191-2 for an index of PHMSA reporting forms used for federal reporting. Report forms and instructions can be downloaded from the PHMSA-OPS website at www.phmsa.dot.gov/forms/pipeline-forms.
(b) Federal reports for gathering lines are based on the definitions found in §192.8.
(c) Additional state reporting requirements may exist for intrastate facilities.
(d) For National Pipeline Mapping System submission requirements, see §191.29.
(e) Operators will need to reflect changes due to service conversion (see §192.14) or product change (see §191.22(c)(1)(vi)) on subsequent Annual Reports.
(f) Transmission, Type A gathering, Type B gathering, and Type C gathering operators who also have Type R gathering pipelines will have to submit separate annual and incident reports for the Type R pipelines (§191.17).

§191.21

OMB control number assigned to information collection.

[Effective Date: 01/18/17]

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.
191.9	PHMSA 7100.1, PHMSA 7100.3.
191.11	PHMSA 7100.1-1, PHMSA 7100.3-1.
191.12	PHMSA 7100.1-2.
191.15	PHMSA 7100.2 PHMSA 7100.3.

(c) The ending of gathering is the furthermost downstream endpoint as follows.
   (1) The inlet of the first gas processing plant that is not located on a transmission line, unless the operator can demonstrate through sound engineering principles that gathering extends to a plant farther downstream.
   (2) The outlet of the farthest downstream gas treatment facility.
   (3) The farthest downstream point where gas produced in the same production field or separate production fields is commingled, subject to the following limitation.
   Limitation: If the endpoint is determined by the commingling of gas from separate production fields, the fields may not be more than 50 miles apart, unless the PHMSA Administrator finds a longer separation distance is justified in a particular case. (See §190.9 for requirements regarding petitions to PHMSA-OPS.)
   (4) The outlet of the farthest downstream compressor station used to increase gathering line pressure for delivery to a transmission line or main.
   (5) The connection to another pipeline downstream of either of the following.
      (i) The endpoints identified in (1), (2), (3), or (4) above.
      (ii) The furthermost downstream production operation.
(d) A gathering line does not include a gas processing plant.

2 TYPE OF GATHERING LINE

After identifying a gathering line, the operator of an onshore gathering line is required to determine whether the gathering line is Type A, Type B, Type C, or Type R (see §192.8(a)). All offshore gathering lines are regulated (see §192.9(b)).

2.1 Type A gathering line.

(a) A Type A gathering line is one located in a Class 2, 3, or 4 location to which either of the following conditions apply.
   (1) A non-metallic line (e.g., plastic or fiberglass) where the MAOP is greater than 125 psig.
   (2) A steel line where the MAOP is equal to or greater than 20% SMYS.
      (i) The stress determination for a steel line is made by using Barlow's formula for hoop stress and multiplying by 0.20. Barlow's formula for hoop stress is:

$$P_{100} = \frac{2St}{D}$$

Where:

P_{100} = Pressure at 100% SMYS, psig
S = Specified Minimum Yield Strength of the pipe
t = Wall thickness, inches
D = Nominal outside diameter, inches (see 2 of the guide material under §192.105)

      (ii) If the gathering line MAOP is equal to or greater than P_{100} multiplied by 0.20, the gathering line is Type A.
      (iii) If the pipe yield strength is unknown, or if the pipe was manufactured in accordance with a specification not listed in Section I of Appendix B to Part 192, see the guide material under §192.107.

(b) Type A gathering lines are subject to the requirements of §192.9(c).

2.2 Type B gathering line.

(a) A Type B gathering line is one that meets both of the following conditions.
   (1) Condition 1 - Material and MAOP.
      (i) A steel pipeline where the MAOP is less than 20% SMYS, or

(ii) A non-metallic pipeline (e.g., plastic or fiberglass) where the MAOP is equal to or less than 125 psig.

(2) Condition 2 - Class location.

(i) A pipeline that lies within a Class 3 or Class 4 location (if so, it is considered an "Area 1" under §192.8(b)), or

(ii) A pipeline that lies within a Class 2 location that the operator determines by choosing any one of the following three methods (if so, it is considered an "Area 2(a)," "Area 2(b)," or "Area 2(c)" under §192.8(b)).

(A) A Class 2 location (Area 2(a)).

(B) An area extending 150 feet on each side of the centerline of any continuous 1 mile of pipeline that includes more than 10 but fewer than 46 dwellings, plus a safety buffer (Area 2(b)).

(C) An area extending 150 feet on each side of the centerline of any continuous 1,000 feet of pipeline and including 5 or more dwellings, plus a safety buffer (Area 2(c)).

(b) Type B, Area 2 gathering line safety buffer.

After determining that the gathering line is a Type B, Area 2(b) or (c), the safety buffer is a length of pipeline that extends upstream and downstream from the area to a point where the line is at least 150 feet from the nearest dwelling in the area. However, if a cluster of dwellings in the area qualifies a line as a Type B gathering line, the Type B classification ends 150 feet from the outermost dwellings in the cluster.

Note: The safety buffer could possibly extend into a Class 1 location.

(c) Examples of Area 2(b) and (c) length determinations.

(1) Area 2(b) example. In Figure 192.8A, the length of the Type B segment is determined using the sliding mile method. This is similar to a typical class location survey, with the exception that 150 feet is used instead of 660 feet on either side of the centerline of the pipe. The length of Type B pipe can be adjusted shorter or longer depending on the locations of the dwellings within the mile.

(d) Type B gathering lines are subject to the requirements of §192.9(d).

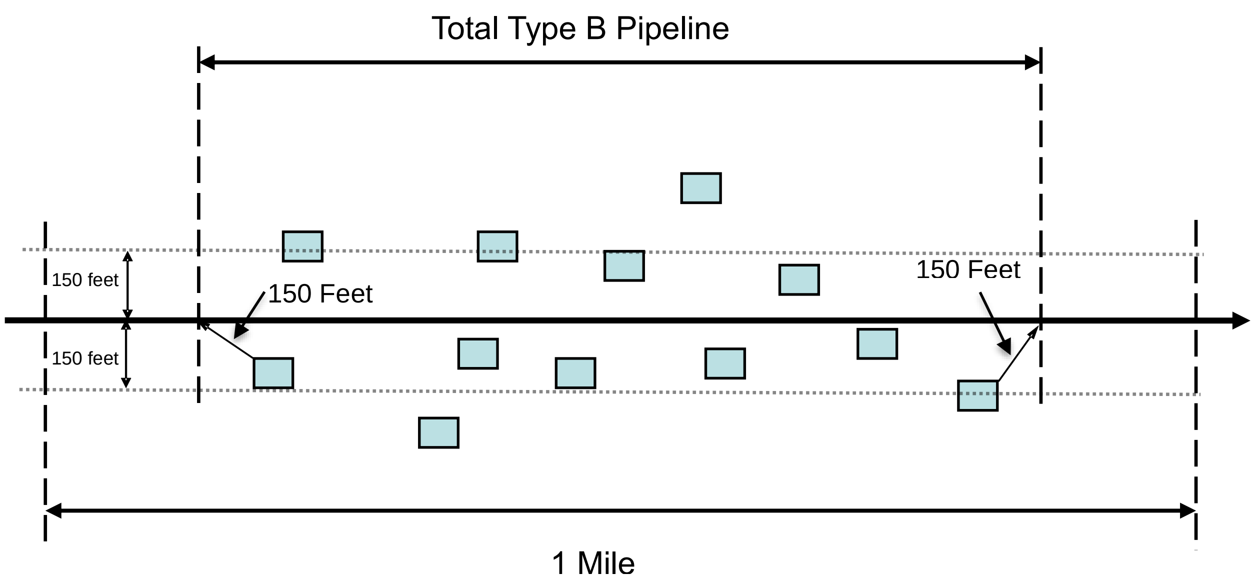


FIGURE 192.8A

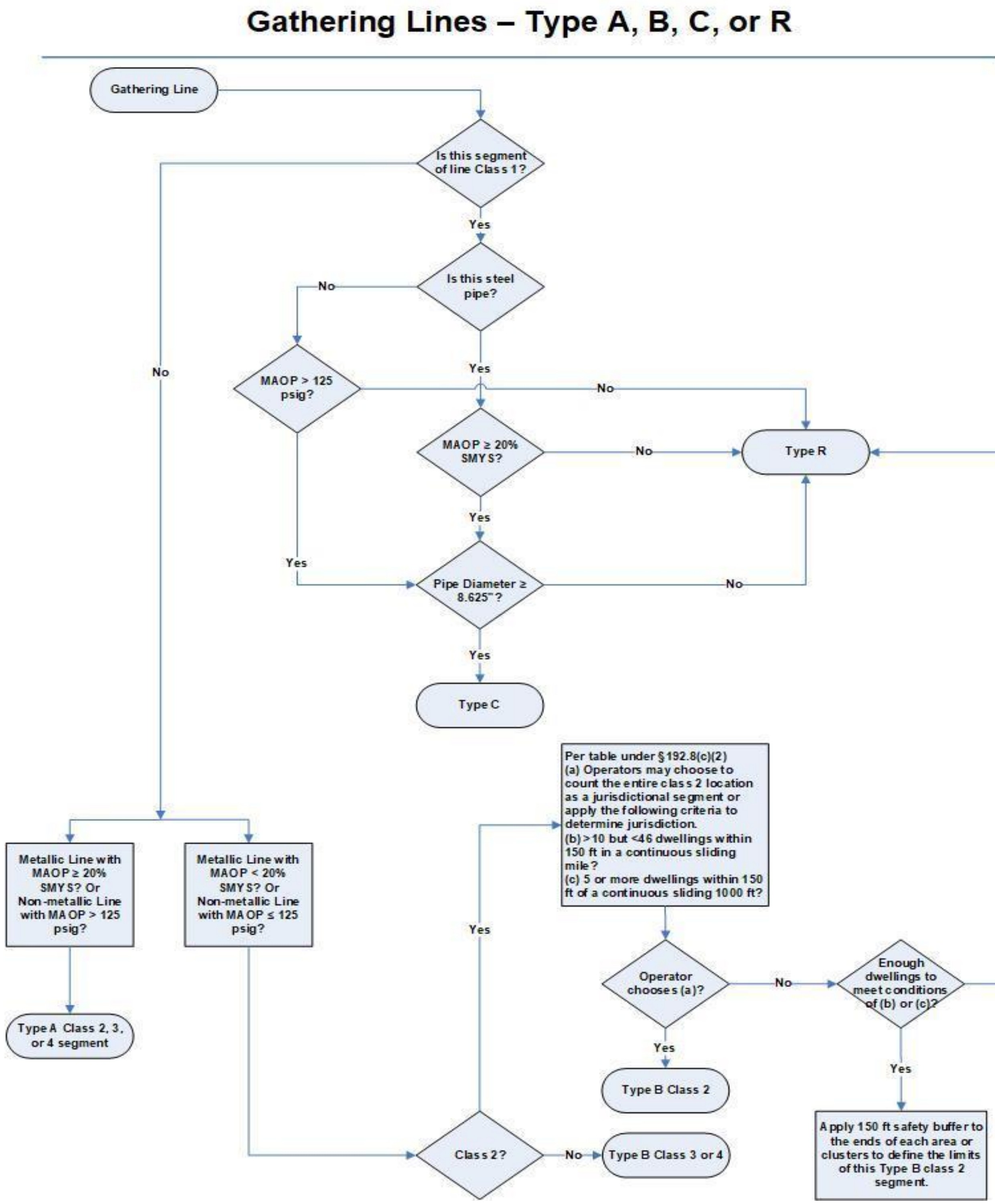


FIGURE 192.8C

(f) With respect to the incorporation by reference of API RP 1170 and API RP 1171 in this section, the non-mandatory provisions (*i.e.,* provisions containing the word ''should'' or other nonmandatory language) are adopted as mandatory provisions under the authority of the pipeline safety laws except when the operator includes or references written technical justifications in its program or procedural manual, described in paragraph (a)(5) of this section, as to why compliance with a provision of the recommended practice is not practicable and not necessary for safety with respect to specified underground storage facilities or equipment. The justifications for any deviation from any provision of API RP 1170 and API RP 1171 must be technically reviewed and documented by a subject matter expert to ensure there will be no adverse impact on design, construction, operations, maintenance, integrity, emergency preparedness and response, and overall safety and must be dated and approved by a senior executive officer, vice president, or higher office with responsibility of the underground natural gas storage facility. An operator must discontinue use of any variance where PHMSA determines and provides notice that the variance adversely impacts design, construction, operations, maintenance, integrity, emergency preparedness and response, or overall safety.

[Amdt. 192-122, 81 FR 91873, Dec. 19, 2016]

GUIDE MATERIAL

1 API RECOMMENDED PRACTICES

Guidance provided in API RP 1170 and API RP 1171 (see §192.7 for IBR) for the operation of underground natural gas storage facilities (UNGSFs) is represented as "recommended practices." However, requirements for solution-mined salt cavern and depleted hydrocarbon and aquifer reservoir UNGSFs are listed in the table below.

UNGSF Type	Constructed Date	IBR Requirements
Solution-Mined Salt Cavern	After March 13, 2020	• API RP 1170 • API RP 1171, Section 8
	Between July 18, 2017 and March 13, 2020	• API RP 1170 • API RP 1171, Section 8
	On or before July 18, 2017	• API RP 1170, Sections 9, 10, 11 • API RP 1171, Section 8
Depleted Hydrocarbon or Aquifer Reservoir	After July 18, 2017	• API RP 1171
	On or before July 18, 2017	• API RP 1171, Sections 8, 9, 10, 11

TABLE 192.12i

2 ADDITIONAL REFERENCES

(a) National standards and the sections referencing them in API RP 1170 and API RP 1171 are listed in the table below.

National Standard	API RP 1170	API RP 1171
API Bulletin 5A2, *Bulletin on Thread Compounds for Casing, Tubing, and Line Pipe*	*	
API Bulletin E3, *Well Abandonment and Inactive Well Practices*		6.7.1
API Guidance Document HF1, *Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines*		6.5.3

TABLE 192.12ii (Continued)

National Standard	API RP 1170	API RP 1171
API Guidance Document HF2, *Water Management Associated with Hydraulic Fracturing*		6.5.3
API Guidance Document HF3, *Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing*		6.5.3
API RP 5A3, *Recommended Practice on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements*	8.4.2.6	
API RP 5A5, *Field Inspection of New Casing, Tubing, and Plain-end Drill Pipe*	*	
API RP 5B1, *Gauging and Inspection of Casing, Tubing and Line Pipe Threads*	*	
API RP 5C1, *Recommended Practice for Care and Use of Casing and Tubing*	8.4.2.5	
API RP 10D-2, *Recommended Practice for Centralizer Placement and Stop-collar Testing*		6.4.5
API RP 10F, *Recommended Practice for Performance Testing of Cementing Float Equipment*	2, 7.6.1	
API RP 13D, *Rheology and Hydraulics of Oil-well Drilling Fluids*	*	
API RP 14B, *Design, Installation, Repair and Operation of Subsurface Safety Valve Systems*		6.2.5
API RP 14E, *Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems*		6.3.5
API RP 49, *Recommended Practice for Drilling and Well Servicing Operations Involving Hydrogen Sulfide*		6.8.1
API RP 51R, *Environmental Protection for Onshore Oil and Gas Production Operations and Leases*		5.5.1, 6.8.1
API RP 53, *Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells*	*	11.5.2
API RP 54, *Recommended Practice for Occupational Safety for Oil and Gas Well Drilling and Servicing Operations*		6.8.1, 11.5.2, 11.6.2
API RP 76, *Contractor Safety Management for Oil and Gas Drilling and Production Operations*		5.5.1, 6.8.1
API RP 1114, *Recommended Practice for the Design of Solution-Mined Underground Storage Facilities*	*	
API RP 1115, *Design and Operation of Solution-mined Salt Caverns Used for Liquid Hydrocarbon Storage*	*	
API Specification 5CT, *Specification for Casing and Tubing*	*	
API Specification 5DP, *Specification for Drill Pipe*	*	
API Specification 5L, *Specification for Line Pipe*	*	
API Specification 6A, *Specification for Wellhead and Christmas Tree Equipment*	*	6.2.1
API Specification 6D, *Specification for Pipeline Valves*	*	
API Specification 10A, *Specification for Cements and Materials for Well Cementing*	2, 7.6.1	6.4.2, 6.7.2
API Specification 14A, *Specification for Subsurface Safety Valve Equipment*		6.2.5
API Standard 65-2, *Isolating Potential Flow Zones during Well Construction*		6.4.5
API Standard 1104, *Welding of Pipelines and Related Facilities*	*	
API Technical Report 5C3, *Calculating Performance Properties of Pipe Used as Casing or Tubing*	2, 8.4.2.3	

TABLE 192.12ii (Continued)

National Standard	API RP 1170	API RP 1171
API Technical Report 10TR1, *Cement Sheath Evaluation*		6.4.6
API Technical Report 10TR3, *Technical Report on Temperatures for API Cement Operating Thickening Time Tests*	*	
API Technical Report 10TR4, *Selection of Centralizers for Primary Cementing Operations*	*	6.4.5
ASTM C150/C150M, *Standard Specification for Portland Cement*		6.4.2, 6.7.2
ASTM D3740, *Standard Practice for Minimum Requirements for Agencies Engaged in Testing and/or Inspection of Soil and Rock as Used in Engineering Design and Construction*	5.4.2.1	
ASTM D3967, *Standard Test Method for Splitting Tensile Strength of Intact Rock Core Specimens*	2, 5.4.2.4	
ASTM D4543, *Standard Practices for Preparing Rock Core as Cylindrical Test Specimens and Verifying Conformance to Dimensional and Shape Tolerances*	2, 5.4.2.3	
ASTM D4645, *Standard Test Method for Determination of In-Situ Stress in Rock Using Hydraulic Fracturing Method*	2, 5.4.4	
ASTM D7012, *Standard Test Methods for Compressive Strength and Elastic Moduli of Intact Rock Core Specimens under Varying States of Stress and Temperatures*	2, 5.4.2.5.1, 5.4.2.5.2, 5.4.2.5.3	
ASTM D7070, *Standard Test Methods for Creep of Rock Core Under Constant Stress and Temperature*	2, 5.4.2.6	
U.S. Bureau of Safety and Environmental Enforcement Report RLS0116, *Cement Plug Testing: Weight vs pressure Testing to Assess Viability of a Wellbore Seal between Zones*		6.7.2

* Standard referenced in API RP 1170, Section 2, but not associated with another particular section.

TABLE 192.12ii

(b) For additional guidance on managing risk for gas storage operations, the operator may refer to the following.

(1) ISO 31000, *Risk Management – Guidelines.*
(2) ISO 31010, *Risk Management – Risk assessment techniques.*
(3) ISO 55000 Asset Management – PAS 55-1:2008, *Asset management – Part 1: Specification for the optimized management of physical assets*, PAS 55-2:2008 *Asset management – Part 2: Guidelines for the application of PAS 55-1.*
(4) ASME B31.8S, *Managing System Integrity of Gas Pipelines.*
(5) "Pipeline Risk Management Manual," W. Kent Muhlbauer, Gulf Publishing Company, ISBN: 0750675799.

3 WRITTEN PROCEDURES

Each operator must keep records necessary to administer procedures and review and update the required manuals at intervals not exceeding 15 months, but at least once each calendar year (§192.12(c)).

3.1 Operations and Maintenance (O&M) procedures.

Storage field operators may have a pipeline O&M manual because of the transmission lines within the field. Some of the operations and maintenance tasks for storage operations might be similar to pipeline tasks (e.g., corrosion monitoring). Operators of underground storage fields should consider aligning storage procedures with existing pipeline procedures where applicable to avoid duplication or conflicting instructions. See guide material under §192.605 for information regarding O&M manual.

3.2 Emergency plans.

Pipeline operators already have emergency plans in place. Storage operators should consider integrating the UNGSF emergency procedures with existing emergency plans (see guide material under §192.615). Some unique emergency conditions that the storage operator should consider include the following.

(a) Leaking annulus of storage well.
(b) Emergency killing of a well using fluid or downhole plug.
(c) Well blowout.

3.3 Management of change.

Storage operators should consider implementing the management of change process as required for transmission lines (§192.13(d)).

4 UNGSF INTEGRITY MANAGEMENT PROGRAM

4.1 General.

(a) The Storage Integrity Management Program (SIMP) consists of program elements encompassing the plans, processes, and procedures required for UNGSF integrity management. The SIMP will vary from one operator to the next but must address the elements as specified in §192.12(d) and API RP 1170 or 1171. The SIMP should document how the processes and associated procedures will be managed and implemented.
(b) A written program provides a road map for assessment, integration and analysis of data, and courses of action available in managing UNGSF integrity. The program can incorporate or reference existing policies and procedures that may address the elements listed in §192.12(d).
(c) The operator should consider conducting a gap analysis between current policies and procedures and the requirements of §192.12(d) to determine if additional plans, processes, or procedures may be required.

4.2 Development.

The operator should consider the following when developing its Storage Integrity Management Program (SIMP).

(a) Existing O&M procedures.
(b) Existing management systems (e.g., quality assurance, management of change).
(c) Existing environmental and safety programs.
(d) "FAQs" from the PHMSA-OPS website at www.phmsa.dot.gov/pipeline/underground-natural-gas-storage/ungs-frequently-asked-questions.
(e) "Inspection Protocols" from the PHMSA-OPS website at: www.phmsa.dot.gov/forms/phmsa-underground-natural-gas-storage-ia-question-set.
(f) Key documents and resources from the PHMSA-OPS website at www.phmsa.dot.gov/pipeline/underground-natural-gas-storage/underground-natural-gas-storage-key-documents.
(g) Documents incorporated by reference (see 1 above).
(h) Existing or previous risk assessments.
(i) Existing emergency procedures

4.3 Updates and Changes

It is anticipated that there will be changes over time to an operator's SIMP. A UNGSF operator must document the changes and the reasons for them including decisions, analyses, and processes used to change elements of the SIMP (§192.12(d)(4)). The UNGSF operator should maintain previous versions or revision history of the SIMP for the life of the UNGSF. This documentation can be in electronic format. Factors that might cause a change to the SIMP include the following.

(a) Information obtained from downhole assessments.
(b) Operating experience.
(c) The operator's understanding that the specific integrity threats and their relative importance may change.
(d) The operator's understanding about the capabilities of a specific integrity assessment technology, tool, or process.

(e) Threats, consequences, and subsequent risks that evolve over time causing an operator to reprioritize future integrity assessments.
(f) Identification of a change to a consequence, such as encroachment by the public or commercial entity.
(g) Changes in the operating parameters of the UNGSF.
(h) Acquisition or divestiture of storage facilities that could impact integrity assessment priorities.

5 INTEGRITY MANAGEMENT RISK-ASSESSMENT

(a) UNGSF operators must (§192.12(d)) develop a process for identification of threats and hazards from underground storage operations, and that the likelihood and consequences (risk) of potential adverse events are analyzed and estimated. UNGSF operators should ensure that risk analysis processes include elements identified within Table 1 of API RP 1171 (see §192.7 for IBR).
(b) Per API RP 1171, Section 8.2, the risk assessment process must include the following.
    (1) Data Collection. Identification and collection of information relevant to the storage field as part of risk assessment.
    (2) Risk Identification. Identification of potential threats and hazards (Table 1 of API RP 1171) to the storage facility from within the areas of review and buffer zone.
    (3) Risk Analysis. Analysis of the likelihood of events and consequences related to the events.
    (4) Risk Evaluation. Determination of risk ranking to develop preventative and mitigative (P&M) measures (Table 2 of API RP 1171) to monitor or reduce risk.
    (5) Record Keeping. Documentation of risk evaluation and decision basis for P&M measures.
    (6) Periodic Evaluation. Periodic evaluation of risk assessment and determination of need to escalate the implementation or modification of P&M measures.
    (7) Program Evaluation. Evaluation of risk management program using performance measures.
(c) The risk assessment should address potential threat interactions, such as casing damage during service work that could exacerbate internal corrosion threat.
(d) Data used as inputs to the risk analysis should come from design, construction, testing, operating history, routine integrity monitoring, and inspection records. The operator should validate identified data used in the risk analysis to ensure data accuracy. Should validated data not be available, operators should make conservative assumptions and assign conservative values when conducting risk analysis. Examples of risk analysis input data may include the following.
    (1) Reservoir studies.
    (2) Drilling and workover records.
    (3) Material records.
    (4) Well and reservoir performance data.
    (5) Well logs.
(e) Reassessment of UNGSF risk analysis must be completed within 7 years of the previous risk assessment per §192.12(d)(3). Operators should consider more frequent assessment of risk based upon newly acquired data (e.g., well logs) or when changes occur that could affect previously identified threats, likelihood of failure, and consequence of failure of wells, reservoirs, and caverns. The interval should be of sufficient length that the quantity of new data and information that is brought into the analysis is meaningful and that any developing trends have sufficient data to be identifiable.
(f) Per API RP 1171, Section 8.7.3, if new threats or hazards are identified, or the impact of existing threats or hazards significantly changes, the operator must assess the risk associated with new conditions and evaluate and prioritize risk management options.

6 PREVENTATIVE AND MITIGATIVE (P&M) MEASURES

(a) UNGSF operators must develop P&M measures to monitor or reduce the risks to the storage facilities (API RP 1171, Section 8.6.2). The P&M measures are identified to reduce the likelihood or reduce the consequence of events related to the unique threats recognized in the most recent risk assessment. The P&M measures can include programs, methods, tools, or routine condition monitoring activities to monitor and manage risk. Examples of P&M measures for storage activities are listed in API RP 1171, Section 8.6, Table 2. In addition to those P&M measures listed in Table 2, UNGSF operators might consider evaluating pipeline activity that could affect the integrity of the downhole operations (e.g., pipeline internal corrosion control mitigation activities (see §192.478)).

(b) Not all risks need a P&M measure if the level of risk is acceptable or if it is not necessary to reduce risk by further efforts.

(c) The operator must review the results of P&M measures to determine the effectiveness of managing risk based on site-specific conditions. Per API RP 1171, Section 8.7.2, the operator must define a review frequency for the P&M measures.

§192.13

What general requirements apply to pipelines regulated under this part?

[Effective Date: 05/24/23]

(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 line to which this part did not apply until April 14, 2006.	**March 15, 2007.**

(3) Regulated onshore gathering line 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/ANSI 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.

[Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-30, 42 FR 60146, Nov. 25, 1977; Amdt. 192-102, 71 FR 13289, Mar. 15, 2006; Amdt. 192-129, 86 FR 63294 Nov. 15, 2021, Amdt. 192-132, 87 FR 52224, Aug. 24, 2022]

GUIDE MATERIAL

This guide material is under review following Amendment 192-132.

See Guide Material Appendix G-192-17. Also, see the "Glossary of Commonly Used Terms" under §192.3 for definition of "*otherwise changed*."

§192.14

Conversion to service subject to this part.

[Effective Date: 03/24/17]

(a) A steel pipeline previously used in service not subject to this part qualifies for use under this part if the operator prepares and follows a written procedure to carry out the following requirements:

(1) The design, construction, operation, and maintenance history of the pipeline must be reviewed and, where sufficient historical records are not available, appropriate tests must be performed to determine if the pipeline is in a satisfactory condition for safe operation.

(2) The pipeline right-of-way, all aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline.

(3) All known unsafe defects and conditions must be corrected in accordance with this part.

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

(b) Each operator must keep for the life of the pipeline a record of the investigations, tests, repairs, replacements, and alterations made under the requirements of paragraph (a) of this section.

(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.

[Issued by Amdt. 192-30, 42 FR 60146, Nov. 25, 1977; Amdt. 192-123, 82 FR 7997, Jan. 23, 2017]

GUIDE MATERIAL

1 TYPES

The following are some of the types of steel pipelines that might be converted to gas service under this part.

(a) Gas pipelines abandoned prior to effective date of Part 192.
(b) Liquid petroleum pipelines, such as oil or gasoline.
(c) LPG pipeline systems.
(d) Nonjurisdictional pipelines.
(e) Pipelines carrying chemical or industrial products, such as carbon dioxide, nitrogen, air or liquid chemicals.
(f) Slurry pipelines.

2 TESTS AND INSPECTION

The following are examples of appropriate tests and inspections that may be used to evaluate pipelines where sufficient historical records are not available. See §192.14(a)(1).

(a) Corrosion surveys.
(b) Ultrasonic inspections.
(c) Acoustic emissions.
(d) Material and tensile tests. See Appendix B to Part 192.
(e) Internal inspections.
(f) Radiographic inspections.
(g) Pressure tests. See §192.619.

3 VISUAL INSPECTION OF UNDERGROUND SEGMENTS

Generally, the segments to be inspected should be at locations where the worst probable conditions may be expected. The following criteria should be used for the selection of inspection sites.

(a) Corrosion surveys (inadequately protected segments, poor coating, stray currents, and interference).
(b) Pipeline component locations.
(c) Locations subject to mechanical damage.
(d) Foreign pipeline crossings.
(e) Locations subject to damage due to chemicals, such as acid.
(f) Segments subject to coating deterioration due to soil stresses and internal or external temperature extremes.
(g) Population density.

4 REGULATORY DOCUMENTS

For pipelines being converted under this section, the operator should review it's procedural manual for operations, maintenance, and emergencies and its public education program for compliance to Part 192 prior to placing the converted line into gas service.

§192.15

Rules of regulatory construction.

[Effective Date: 11/12/70]

(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.

GUIDE MATERIAL

No guide material necessary.

§192.16

Customer notification.

[Effective Date: 05/04/98]

(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 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.

[Issued by Amdt. 192-74, 60 FR 41821, Aug. 14, 1995 with Amdt. 192-74 Correction, 60 FR 43028, Aug.18, 1995 and Amdt. 192-74A, 60 FR 63450, Dec. 11, 1995; Amdt. 192-84, 63 FR 7721, Feb. 17, 1998 with Amdt. 192-84 Confirmation, 63 FR 38757, July 20, 1998 and Amdt. 192-84 Correction, 63 FR 38758, July 20, 1998]

GUIDE MATERIAL

No guide material necessary.

§192.18

How to notify PHMSA.

[Effective Date: 05/24/23]

(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 the 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 § 192.937 a notification for use of a different integrity assessment method, analytical method, compliance period, sampling approach, pipeline material, or technique (*e.g.,* "other technology" or "alternative equivalent technology") than otherwise prescribed in those

(d) 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.

[Issued by Amdt. 192-125, Oct. 1, 2019; Amdt. 192-129, 86 FR 63294 Nov. 15, 2021; Amdt. 192-130, 87 FR 20940, Apr. 8, 2022, Amdt. 192-132, 87 FR 52224, Aug. 24, 2022]

GUIDE MATERIAL

This guide material is under review following Amendment 192-132.

1 NOTIFICATION INFORMATION

Operators are required to use an OPID in any notification to PHMSA (§191.22(d)).
See the following code sections for information regarding specific notification requirements.
(a) Section 192.506(b) for notification requirements concerning spike testing.
(b) Sections 192.607(e)(4) and 192.607(e)(5) for notification requirements concerning material verification
(c) Sections 192.624(c)(2)(iii) and 192.624(c)(6) for notification requirements concerning MAOP reconfirmation.
(d) Section 192.632(b)(3) for notification requirements concerning Engineering Critical Assessment.
(e) Sections 192.712(d)(3)(iv) and 192.712(e)(2)(i)(E) for notification requirements concerning analysis of predicted failure pressure.
(f) Section 192.805(i) for notification of significant modifications to OQ program.
(g) Section 192.909, when the operator makes substantial changes to the integrity management program. Notifications should include the description and reason for the program or schedule change.
(h) Sections 192.710, 192.921, and 192.937, when the operator makes use of other technologies for assessment. Notifications should include the following information.
    (1) Description and rationale for new technology.
    (2) Where the technology will be used.
    (3) Procedures for applying the technology.
    (4) Procedures for qualifying persons performing the assessment and analyzing the results.
(i) Section 192.927, when ICDA is used to assess a covered segment with an electrolyte present in the gas stream (wet gas ICDA). Notifications must include a plan demonstrating how ICDA effectively addresses internal corrosion.
(j) Section 192.933(a)(1), when the operator cannot meet the schedule and cannot provide safety through temporary pressure reduction. Notifications should include the following information.
    (1) Reason why the schedule cannot be met or temporary pressure reduction cannot be implemented.
    (2) How public safety will be maintained.
(k) Section 192.933(a)(2), when a pressure reduction exceeds 365 days. Notifications must include the following information.
    (1) Reason for remediation delays.
    (2) Technical justification that pressure reduction is sufficient for maintaining public safety.

2 STATE NOTIFICATION

Where PHMSA-OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that state, an operator must also notify the state pipeline safety agency (§192.18(b)). A reference for state contacts is available at www.napsr.org.

SUBPART C
PIPE DESIGN

§192.101
Scope.

[Effective Date: 11/12/70]

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

GUIDE MATERIAL

No guide material necessary.

§192.103
General.

[Effective Date: 11/12/70]

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.

GUIDE MATERIAL

1 GENERAL

The minimum wall thickness for pressure containment as calculated under §192.105 may not be adequate to withstand other forces to which the pipeline may be subjected. Consideration should be given to stresses associated with transportation, handling the pipe during construction, weight of water during testing, buoyancy, geotechnical, or geological forces, and other secondary loads that may occur during construction, operation, or maintenance. Consideration should also be given to welding or mechanical joining requirements.

2 NON-STEEL PIPE

The minimum wall thickness for materials other than steel pipe are prescribed elsewhere in Part 192. See §§192.123 and 192.125.

3 REFERENCES

See Guide Material Appendix G-192-13 for design considerations. Numerous references are available for the calculation, investigation, or mitigation of external forces on pipelines. Methods include reliance on experience, empirical formula, and finite element analysis. A partial listing of references follows.

(a) API RP 5L1, "Recommended Practice for Railroad Transportation of Line Pipe" (see listing in §192.7, not IBR for §192.103).

(b) API RP 5LW, "Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels" (see listing in §192.7, not IBR for §192.103).
(c) API RP 1102, "Steel Pipelines Crossing Railroads and Highways."
(d) API RP 1117, "Movement of In-Service Pipelines."
(e) ASCE 428-5, "Guidelines for the Seismic Design of Oil and Gas Pipeline Systems" (Discontinued).
(f) GRI-91/0283, "Guidelines for Pipelines Crossing Railroads."
(g) GRI-91/0284, "Guidelines for Pipelines Crossing Highways."
(h) PRCI PR-000-18COMP-R04, “Geohazards Compendium.”
(i) INGAA Foundation Report 2015-03, “Mitigation of Land Movement in Steep and Rugged Terrain for Pipeline Projects: Lessons Learned from Constructing Pipelines in West Virginia.”
(j) USGS Report 2008-1164, “Landslide and Land Subsidence Hazards to Pipelines.”

§192.105
Design formula for steel pipe.

[Effective Date: 07/13/98]

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

$$P = \frac{2\,St \times F \times E \times T}{D}$$

***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 ºF (482 ºC) at any time or is held above 600 ºF (316 ºC) for more than 1 hour.

[Amdt. 192-47, 49 FR 7567, Mar. 1, 1984; Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL

1 WALL THICKNESS

The nominal wall thickness (t) should not be less than that determined by the considerations given in the guide material under §192.103.

(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)

[Amdt. 192-31, 43 FR 13880, Apr. 3, 1978 with Amdt. 192-31 Correction, 43 FR 43308, Sept. 25, 1978; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-94, 69 FR 32886, June 14, 2004; Amdt. 192-103, 71 FR 33402, June 9, 2006; RIN 2137-AE26, 73 FR 79002, Dec. 24, 2008; Amdt. 192-111, 74 FR 62503, Nov. 30, 2009; Amdt. 192-114, 75 FR 48593, Aug. 11, 2010; Amdt. 192-124, 83 FR 58694, Nov. 20, 2018]

GUIDE MATERIAL

This guide material is under review following Amendment 192-124.

1 NATURAL AND OTHER GAS

(a) Hydrostatic Design Basis (HDB) values are awarded by the Hydrostatic Stress Board (HSB) of the Plastics Pipe Institute (PPI) and are listed in PPI TR-4, which can be accessed at:
www.plasticpipe.org

(b) ASTM D2513 (see §192.7 for IBR as listed specification) requires elevated temperature HDB listings for plastic piping materials used at temperatures above 73 °F. PPI publishes elevated temperature HDB values for PE and PA materials in TR-4.

(c) Long-term hydrostatic strength (LTHS) for reinforced thermosetting plastic covered by ASTM D2517 (see §192.7 for IBR as listed specification) is 11,000 psi.

(d) HDB values apply only to materials meeting all the requirements of ASTM D2513 and are based on engineering test data analyzed in accordance with ASTM D2837, "Standard Test Method for Obtaining Hydrostatic Design Basis for Thermoplastic Pipe Materials or Pressure Design Basis for Thermoplastic Pipe Products."

(e) HDB values at 73 °F for thermoplastic materials covered by ASTM D2513 are listed in Table 192.121i. The values used in the design formula for thermoplastic materials are actually HDB values that are a categorized value of the long-term hydrostatic strength.

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 must meet the requirements of §§192.634 and 192.636. The requirements of this paragraph apply when the applicable pipeline replacement project involves a valve, either through addition, replacement, or removal. This paragraph's installation requirements do not apply to pipe segments in Class 1 or Class 2 locations that have a PIR, as defined in §192.903, that is less than or equal to 150 feet. An operator may request an extension of the installation compliance deadline requirements of this paragraph 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 paragraphs (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 (7½) 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.

[Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-130, 87 FR 20940, Apr. 8, 2022]

GUIDE MATERIAL

1 GENERAL

When installing onshore transmission pipeline replacements, the spacing requirements for sectionalizing block valves in §192.179(a) are not required if the valve spacing in §192.179(h) is met.

2 VALVE SPACING ON OFFSHORE-ONSHORE PIPELINES

(a) Where the distance between valves on a combined segment of a new offshore-onshore pipeline exceeds the valve spacing requirements for onshore pipelines, consideration should be given to the installation of a block valve at the nearest practical location to the land juncture of the pipeline segment.

(b) Sectionalizing block valves and blowdown valves associated with Type A and Type B gathering lines might need to be installed or relocated when any portion of a line is replaced, relocated, or otherwise changes.

3 BLOWDOWN RECOMMENDATIONS

3.1 Blowdown duration and timing.

(a) The operator should minimize blowdown time by properly sizing and placing blowdown discharges to:
  (1) Reduce the time gas is venting through a rupture and susceptible to ignition.
  (2) Reduce the duration of a gas fire, minimizing the impact on life and property.
  (3) Reduce the impact on flow capacity while the pipeline is out of service.

(b) The operator should consider the following when scheduling non-emergency blowdowns for pipeline maintenance or repairs.
  (1) Blow down during daylight hours to minimize noise emission impact on the public.
  (2) Blow down during favorable atmospheric conditions, so that vented gas is efficiently dispersed into the atmosphere and does not travel toward potential ignition sources or populated areas.
  (3) Provide advance notification to local residents, law enforcement, fire officials, and other pipeline operators in the area.
  (4) Coordinate blowdowns with the operator’s personnel responsible for operation of the pipeline as well as customers whose service may be impacted by the blowdowns.

3.2 Blowdown location.

The following should be considered when locating blowdown discharges.

(a) Discharges should be located a sufficient distance away from buildings such that:
  (1) Should vented gas ignite, buildings will not be in danger of ignition or heat damage.
  (2) Noise emissions from blowdowns will have minimal impact on the public.
  (3) Methane emissions from blowdowns will have minimal public and environmental impact.

(b) Discharges should be located a sufficient distance away from overhead electric lines, and other potential ignition sources, so that the explosive gas / air concentrations of the dispersed vented gas do not come in contact with an ignition source.

3.3 Blowdown emissions.

Where practicable, operators should consider the following emission reducing actions during non-emergency blowdowns.

(a) Reduce methane emissions for environmental and economic reasons by:
  (1) Using existing compressor or regulator stations to pull down the pipeline pressure before blowdown.
  (2) Using a portable evacuation compressor to pull down the pipeline pressure by pumping the gas into another pipeline before blowdown.
  (3) Flaring the blowdown gas.

(b) Reduce entrained liquid emissions by:
  (1) Using blowdown separators.
  (2) Flaring the blowdown gas.

(c) Reduce noise emissions by using blowdown silencers, particularly in populated areas.

4 RUPTURE MITIGATION VALVE (RMV) OR ALTERNATIVE EQUIVALENT TECHNOLOGY

4.1 Applicability.

(a) Transmission lines with a diameter greater than or equal to 6 inches installed after April 10, 2023, must address RMV requirements (see §192.179(e) or (f)).
  (1) Segments in Class 1 or Class 2 locations with a PIR less than or equal 150 feet are exempt.
  (2) If a new line to be constructed does not require installation of a valve to meet minimum valve spacing requirements, an RMV or alternative equivalent technology is not required.
  (3) If a replacement project neither adds nor removes a valve, an RMV or alternative equivalent

technology is not required.

(b) For *entirely replaced onshore transmission pipeline segments* (as defined in §192.3), operators should consider the following.
   (1) Effects of multiple projects on the same pipeline,
   (2) Timing of replacement projects.
   (3) Planned and emergency replacements.

4.2 PHMSA notifications.

(a) Manual valves can be considered as an alternative equivalent technology. If they are located at a continuously manned compressor station, notification to PHMSA is not required. Other locations are subject to notification. See §192.179(g).
(b) Requests for compliance deadline extensions may be submitted to PHMSA for each new pipeline on a case-by-case basis.
(c) Extension requests document the economic, technical, operational, or other reasons why compliance deadline cannot be met, as well as safety.
(d) If using alternative equivalent technology, see guide material under §192.18.

5 PROTECTIONS FROM TAMPERING AND DAMAGE

The operator should consider minimizing the potential risks to the system from unauthorized operation of valves. The operator should consider deterrents where practicable such as the following.

(a) Underground vaults.
(b) Removal of operating wheels.
(c) Chain and locking devices.
(d) Remote controlled valves.
(e) Protected SCADA design for remote controlled valves.
(f) Warning signs stating the consequences or penalties of tampering with the facility. [Suggested in OPS Advisory Bulletin ADB-2016-06 (81 FR 89183, Dec. 9, 2016; reference Guide Material Appendix G 192-1, Section 2).]

§192.181

Distribution line valves.

[Effective Date: 11/12/70]

(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.

GUIDE MATERIAL

1 HIGH-PRESSURE DISTRIBUTION LINE VALVES (§192.181(a))

1.1 Physical characteristics.

The following physical characteristics should be considered when establishing high-pressure distribution system line valve locations.

(a) Size of area to be isolated.
(b) Topographic features, such as rivers, major highways and railroads.
(c) Number of valves necessary to isolate the area.

1.2 Operating characteristics.

The following operating characteristics should be considered when establishing locations for high-pressure distribution system line valves.

(a) Total number of customers and such customers as hospitals, schools, commercial, and industrial users that would be affected.
(b) Time required for available personnel to carry out isolation procedures.
(c) Time required for controlling the pressure in the isolated area by such means as venting and transferring gas to adjacent systems.
(d) Time required for available personnel to restore service to the customer.

2 REGULATOR STATION ISOLATION

Section 192.181(b) details the requirement for a valve on the inlet piping. When a distribution system is supplied by more than one regulator station, or when the system may reasonably be expected to create a significant backfeed, consideration should be given to isolating the stations from backfeed during an emergency. This may be accomplished by one of the following:

(a) Installing a valve on the station outlet piping.
(b) Utilizing valving in the distribution system to prevent a backfeed into the station.
(c) Developing a procedure to shut down all stations supplying the system.

§192.183

Vaults: Structural design requirements.

[Effective Date: 07/13/98]

(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 gage 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.

[Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL

1 SUPPORTS

Equipment and piping in vaults or pits should be suitably supported by metal, masonry, or concrete supports. Control piping should be placed and supported so that its exposure to injury or damage is reduced to a minimum.

2 OPENINGS

2.1 Location.

(a) Vault or pit openings should be located so as to minimize the hazards of tools or other objects falling upon the regulator, piping or other equipment. Control piping and the operating parts of the equipment installed should not be located under an opening unless such parts are suitably protected from workers stepping on them.

(b) In designing the vault or pit to protect installed equipment, consideration should be given to incidents that may cause portions of the roof or cover to fall into the vault.

2.2 Cover.

A circular cover should be installed, or other suitable precautions should be taken, if a vault or pit opening is to be located above equipment that could be damaged by a falling cover.

3 CONSIDERATIONS TO MINIMIZE DAMAGE BY OUTSIDE FORCES

See Guide Material Appendix G-192-13.

§192.185
Vaults: Accessibility.

[Effective Date: 11/12/70]

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.

GUIDE MATERIAL

No guide material necessary.

§192.187
Vaults: Sealing, venting, and ventilation.

[Effective Date: 07/13/98]

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.

[Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL

DUCTING

Where ducts are used, the outside end of the ducts should be equipped with a suitable weatherproof fitting or vent-head designed to prevent foreign matter from entering or obstructing the duct. The effective area of the openings in such fittings or vent-heads should be at least equal to the cross-sectional area of a 4 inch duct. The horizontal section of the ducts should be as short as practical and pitched to prevent the accumulation of liquids. The number of bends and offsets should be reduced to a minimum and provisions should be incorporated to facilitate periodic cleaning. Where two ducts are employed, it may be desirable to locate one internal vent at a higher elevation than the other for improved ventilation.

§192.189

Vaults: Drainage and waterproofing.

[Effective Date: 03/06/15]

(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).

[Amdt. 192-76, 61 FR 26121, May 24, 1996 with Amdt. 192-76 Correction, 61 FR 36825, July 15, 1996; Amdt. 192-119, 80 FR 168, Jan. 5, 2015]

GUIDE MATERIAL

Equipment installed in vaults should be designed to continue to operate safely if submerged.

§192.191
[Reserved]
[Effective Date: 01/22/19]

[Amdt. 192-3, 35 FR 17659, Nov. 17, 1970; Amdt. 192-58, 53 FR 1633, Jan. 21, 1988; Amdt. 192-114, 75 FR 48593, Aug. 11, 2010; Amdt. 192-119, 80 FR 168, Jan. 5, 2015; Amdt 192-124, 83 FR 58694, Nov. 20, 2018]

§192.193
Valve installation in plastic pipe.
[Effective Date: 11/12/70]

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.

GUIDE MATERIAL

1 LOADING IMPOSED BY VALVE OPERATION

Common methods to prevent excessive strains in plastic pipe at valve installations include the following.

(a) Using a valve having a low operating torque.
(b) Anchoring the valve body to resist twisting.
(c) Making the transition from plastic-to-metal some distance from the valve. Transition pieces approximately 2 feet long will usually provide sufficient stabilization. However, each installation should be designed to prevent excessive strain on the plastic pipe.
(d) Installing protective sleeves, designed to mitigate the stresses imposed on the plastic pipe in the transition area between the valve and the plastic piping, should be considered if undue stresses at this joint are anticipated, or if recommended by the manufacturer. The installation of protective sleeves, in addition to providing adequate backfill and compaction around the transition area, reduces excessive bending and shear stresses. For protective sleeves, see guide material under §192.367.

2 SECONDARY STRESSES

2.1 Transitions.
The transition from plastic pipe to metal or to a more rigid section of plastic pipe should be supported by undisturbed or well-compacted soil, by bridging, or by sleeve encasement. In addition to providing adequate backfill and compaction around the transition area, the installation of protective sleeves or bridging should be considered to reduce excessive bending and shear stresses. These stresses have been known to cause premature brittle-like failures in some pre-1982 PE piping materials. For protective sleeves, see guide material under §192.367.

2.2 Valve enclosures.
Where curb boxes or other enclosures are used, they should not be supported by the plastic pipe and should not in any way impose secondary stresses on the plastic pipe.

2.3 Coiled pipe.
Valves installed in thermoplastic piping that has been coiled should be suitably restrained to prevent the rotation that may occur.

§192.195
Protection against accidental overpressuring.
[Effective Date: 11/12/70]

(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.

GUIDE MATERIAL

1 GENERAL

1.1 Inlet and outlet pressure rating considerations.
Selection of inlet and outlet pressure ratings of control equipment, such as regulators and control valves, should include consideration of the following.
(a) The maximum inlet pressure at which the regulator will perform in accordance with the manufacturer's specifications.
(b) The maximum pressure to which the inlet may be subjected, under abnormal conditions, without causing damage to the regulator.
(c) The maximum outlet pressure at which the regulator will perform in accordance with the manufacturer's specifications.
(d) The maximum pressure to which the outlet may be subjected under abnormal conditions without causing damage to the internal parts of the regulator.
(e) The maximum outlet pressure which can be safely contained by the pressure-carrying components, such as diaphragm cases, actuators, pilots and control lines.
(f) Springs, orifices, or other parts should not be changed or modified without reevaluation of the above factors.

1.2 Prevention of overpressuring downstream pressure-carrying components.
Recognized methods of preventing overpressuring the downstream pressure-carrying components of control equipment include the following.
(a) Selecting equipment rated to withstand inlet pressure on the downstream side. This is particularly important if the equipment employs internal sensing and the adjacent downstream piping is not otherwise protected.
(b) Connecting the control or sensing line to the downstream pressure system where overpressure protection has been provided.
(c) Protecting the downstream pressure-carrying components by installing a relief valve, regulator, back-pressure valve, or other suitable device in the control or sensing line.

1.3 Flow reversals.

Flow reversals might alter operating pressures along a transmission line from their historical norms and patterns. A review of control equipment and set points should be conducted to confirm the adequacy of existing equipment under the new operating parameters.

1.4 Reference.

See guide material under §192.739.

2 OVERPRESSURE PROTECTION

2.1 Facilities that might at times be bottle-tight.

Suitable protective devices to prevent overpressuring of facilities that might at times be bottle-tight include the following.

(a) Spring-loaded relief valves meeting the provisions of the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 (see listing in §192.7, not IBR for §192.195).
(b) Pilot-operated back-pressure regulators used as relief valves which are designed so that failure of the control lines will cause the regulator to open.
(c) Rupture disks of the type meeting the provisions of the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1.
(d) Devices used to shut in natural gas wells feeding into gathering lines (e.g., well-pressure trip switches, slam shuts, Murphy switches).

2.2 High-pressure distribution systems.

Suitable devices to prevent overpressuring of high-pressure distribution systems include the following.

(a) Spring-loaded relief valves meeting the provisions of the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1.
(b) Weight-loaded relief valves.
(c) A monitoring regulator installed in series with the primary regulator.
(d) A series regulator set to continuously limit the pressure on the inlet of the primary regulator to not more than the maximum allowable operating pressure of the distribution system.
(e) An automatic shut-off device installed in series with the primary pressure regulator. The automatic shut-off device should be set to shut off when the pressure on the distribution system reaches a specified limit that does not exceed the maximum allowable operating pressure. Since this device remains closed until manually reset, it should not be used where it might cause an interruption in service to a large number of customers.
(f) Pilot-operated back-pressure regulators used as relief valves and designed so that failure of the control lines will cause the regulator to open.
(g) Spring-loaded diaphragm relief valves.

2.3 Low-pressure distribution systems.

(a) Suitable protective devices to prevent overpressuring of low-pressure distribution systems including the following.
    (1) A liquid-seal relief device that can be set to open accurately and consistently at the desired pressure.
    (2) See 2.2(b) through 2.2(f) above.
(b) There are several ways that operators can protect low-pressure distribution systems from overpressurization events. Some examples are listed in OPS Advisory Bulletin ADB-2020-02 (85 FR 61097, September 29, 2020; see Guide Material Appendix G-192-1, Section 2).
(c) Low-pressure distribution systems that use only control lines and regulators as the means to detect and prevent overpressurization are not optimal to prevent overpressurization events. Operators should consider overpressure protection that cannot be defeated by a single operator error or equipment failure.
(d) Operators should consider eliminating direct connections between systems operating at different pressures.
(e) Valves connecting a higher-pressure system to a lower-pressure system should be labeled, locked

closed, and clearly identified on drawings to prevent erroneous operation. The operator might consider adding the following.

(1) Double valves or blind plates or both to prevent leak through.
(2) Pressure gauge connections or sensing points on both sides of these valves.
(3) Relief valve downstream of the valve setting.

2.4 Transmission lines.

In addition to the devices listed in 2.2 above, transmission lines may incorporate other suitable means, such as the following.

(a) Compressor overpressure protection (see guide material under §192.169).
(b) Automatic shut off valves or other similar devices that fail closed and require a manual reset.
(c) Rupture discs.

2.5 Gathering lines.

Gathering lines must use overpressure protection devices (§192.195(a)), such as those listed in 2.1, 2.2, 2.3, and 2.4 above. Overpressure protection devices could be located outside of the regulated segment.

2.6 Other considerations.

When bypass piping is included in the station design to facilitate maintenance or inspection of automatic overpressure protection devices, consideration should be given to the following.

(a) Providing a regulator on the bypass piping.
(b) Arranging the bypass piping for series regulators so that only one regulator at a time is bypassed.
(c) When only a manually operated bypass valve is installed:
  (1) Providing upstream and downstream pressure gauges within sight of a person operating the manual valve, and
  (2) Specifying a manual valve that is marked with the flow direction and the operating direction to close it.

§192.197

Control of the pressure of gas delivered from high-pressure distribution systems.

[Effective Date: 10/15/03]

(a) If the maximum actual operating pressure of the distribution system is 60 psi (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 distribution line pressure to pressures recommended for household appliances.

(2) A single port valve with proper orifice for the maximum gas pressure at the regulator inlet.

(3) A valve seat made of resilient material designed to withstand abrasion of the gas, impurities in gas, cutting by the valve, and to resist permanent deformation when it is 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, is able to regulate the downstream pressure within the necessary limits of accuracy and to limit the build-up of pressure under no-flow conditions to prevent a pressure that would cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

(6) A self-contained service regulator with no external static or control lines

(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 that does not have all of the characteristics listed in paragraph (a) of this section is used, or if the gas contains materials that seriously interfere with the operation of service regulators, there must be suitable protective devices to prevent unsafe overpressuring of the customer's appliances if the service regulator fails.

(c) 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 the maximum safe value, the pressure of gas delivered to the customer:

(1) A service regulator having the characteristics listed in paragraph (a) of this section, 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. A device must be installed between the upstream regulator and the service regulator to limit the pressure on the inlet of 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 relief valve or an automatic shutoff that shuts, if the pressure on the inlet of the service regulator exceeds the set pressure (60 p.s.i. (414 kPa) gage or less), and remains closed until manually reset.

(2) A service regulator and a monitoring regulator set to limit, to a maximum safe value, the pressure of the gas delivered to the customer.

(3) A service regulator with a relief valve vented to the outside atmosphere, with the relief valve set to open so that the pressure of gas going to the customer does not exceed a maximum safe value. The relief valve may either be built into the service regulator or it may be a separate unit installed downstream from the service regulator. This combination may be used alone only in those cases where the inlet pressure on the service regulator does not exceed the manufacturer's safe working pressure rating of the service regulator, and may not be used where the inlet pressure on the service regulator exceeds 125 p.s.i. (862 kPa) gage For higher inlet pressures, the methods in paragraph (c)(1) or (2) of this section must be used.

(4) A service regulator and an automatic shutoff device that closes upon a rise in pressure downstream from the regulator and remains closed until manually reset.

[Amdt. 192-3, 35 FR 17659, Nov. 17, 1970; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003]

GUIDE MATERIAL

(a) Suitable protective devices to prevent overpressuring of a customer's appliances — as a result of service regulator failure — with the conditions described in §192.197(b) include the following.
   (1) Monitoring regulator.
   (2) Relief valve.
   (3) Automatic shut-off device.

(b) The protective devices may be installed as an integral part of the service regulator or as a separate unit.

§192.199

Requirements for design of pressure relief and limiting devices.

[Effective Date: 11/12/70]

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 over-pressuring, 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.

[Amdt. 192-3, 35 FR 17659, Nov. 17, 1970]

GUIDE MATERIAL

1 RUPTURE DISKS

Rupture disks should meet the requirements for design as described in the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 (see listing in §192.7, not IBR for §192.199).

2 CONTROL LINES

All control lines should be protected from falling objects, excavation, or other foreseeable causes of damage. They should be designed and installed so that damage to any one control line cannot render both the district regulator and overpressure protective device inoperative.

3 SINGLE INCIDENT (§192.199(g))

3.1 General.

In complying with §192.199(g), the operator should evaluate each district regulating station as to the type and extent of risks that may be expected. Different locations may suggest the need for individual station design, installation considerations and the ability to perform maintenance, inspection and testing activities.

3.2 Examples.

Among the incidents that should be considered in the design of a district regulator station are the following.

(a) Explosions or fire in vault.
(b) Damage by vehicles.
(c) Damage by earthmoving equipment.
(d) Weather and environmental effects.
(e) Others that might result from site selection with respect to airport and railroad operations.

3.3 Protection.

Design and installation considerations include the following.

(a) General.

(1) Protection for relief valve stacks.
(2) Selection of the type of overpressure protection.
(3) Evaluation of the need for redundant protection.
(4) Inspection or maintenance activities that could compromise the integrity of normal overpressure protection. See guide material under §192.739.

(b) Vaults.
(1) Use of a single vault, a double chamber vault, or vaults separated by an appropriate distance.
(2) Structural design. See guide material under §192.183.

(c) Above ground installations.
(1) Location on property under control of the operator.
(2) Space around building(s) for free movement of firefighting equipment.
(3) Use of a single-room building, a double-room building or buildings separated by an appropriate distance.
(4) Use of ventilated buildings made of noncombustible materials. The roof and sidewalls should be designed to relieve the force of an explosion.
(5) Use of posts, guardrails, or barricades.

4 SECURITY (§192.199(h))

Recommended methods for complying with §192.199(h) include the following.

(a) Securing the proper position of any valve under a relief valve that could make the relief valve inoperative or valves that could make the pressure regulating or limiting device ineffective, such as a bypass valve or a control line valve.
(b) Installing duplicate relief valves, each having adequate capacity to protect the system. Isolating valves or a three-way valve should be installed so that it is mechanically impossible to render more than one safety device inoperative at a time.

5 OTHER CONSIDERATIONS TO MINIMIZE DAMAGE BY OUTSIDE FORCES

See Guide Material Appendix G-192-13.

§192.201

Required capacity of pressure relieving and limiting stations.

[Effective Date: 07/13/98]

(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) gage 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. (41 kPa) 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.

[Amdt. 192-9, 37 FR 20826, Oct. 4, 1972; Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL

1 GENERAL

(a) The regulator capacity against which the relief device should protect is the maximum capacity under any single failure mode. The regulator capacity shown in the manufacturer's literature can be used, provided it is known to be the capacity of the regulator in a failed wide-open position. The capacity of the relief device should be based on the maximum capacity of the regulator at the highest pressure in the pipeline that supplies gas to the regulator. This supply pressure may be the maximum operating pressure or the maximum allowable operating pressure defined in §192.3.
(b) The minimum demand on a system may be considered when sizing the relief device provided there is assurance that this minimum flow will always be present.
(c) When there is parallel regulation at a station, the relief capacity for the station should be based on the assumption that the largest capacity regulator fails wide open.
(d) Consideration should also be given to the capacity of the pipeline system supplying the station. If the pipeline is not capable of supplying the failed wide-open capacity of the largest capacity regulator, the relief capacity may be based on the maximum capacity of the pipeline system supplying the station.

2 DETERMINATION OF RELIEF DEVICE CAPACITY

(a) When installed in accordance with the provisions of §192.199(f):
  (1) Relief devices stamped by the manufacturer with a capacity certified under the rules of the ASME Boiler and Pressure Vessel Code, Section VIII (see listing in §192.7, not IBR for 192.201), including recertification stampings, may be considered capable of relieving the capacity stamped. An adjustment should be made to determine the capacity at actual operating conditions.
  (2) Capacities listed in information published by the manufacturer may be used to identify the capacity of the relief device under the stated conditions.
  (3) The use of published data or data otherwise obtained from the manufacturer, and data calculated using recognized formulas, is acceptable.
(b) Relief device capacities as set out above are normally based on the pressure measured at the inlet to the relief device with discharge to atmosphere without vent stack piping. Therefore, when the installation is not in accordance with the provisions of §192.199(f), consideration should be given to the pressure loss in the inlet piping to the relief device, the control piping location and back pressure on the discharge side caused by vent stack piping.
(c) References include the following.
  (1) For the calculations in 2(a)(3) above, UG-131 of the ASME Boiler and Pressure Vessel Code, Section VIII. It is not the intent herein that the capacity be limited to 90% of the actual capacity as set out in Section VIII rules, but only that this information is useful in calculating the actual capacity of a relief device.
  (2) For data on relief devices which have been certified by the NBBI, "Relieving Capacities of Safety Valves and Relief Valves Approved by the National Board" (Discontinued).

(3) For the effect of backpressure on relief device discharge, Figure D-1 of API RP 520 P2, "Sizing, Selection and Installation of Pressure-Relieving Devices in Refineries, Part 2 Installation."

§192.203

Instrument, control, and sampling pipe and components.

[Effective Date: 07/13/98]

(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 takeoff line as near as practicable to the point of takeoff. 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.

[Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL

Instrument, control, and sampling pipe and components which extend to a remote location (adjacent room or building) should be identified by color code, signs, diagrams, or other appropriate means so that proper valves can be located and operated in an emergency. At locations where the identification of such piping is obvious, color coding, marking, diagrams, etc., may not be necessary. Also, see Guide Material Appendix G-192-13 and guide material under §192.199 and 192.739.

§192.204

Risers installed after January 22, 2019.

[Effective Date: 01/22/19]

(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.

[Amdt 192-124, 83 FR 58694, Nov. 20, 2018]

No guide material necessary.

§192.205

Records: Pipeline components.

[Effective Date: 07/01/2020]

(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.

[Amdt. 192-125, Oct. 1, 2019]

GUIDE MATERIAL

(a) Records for pipeline components installed in steel transmission and Type A gathering lines should be traceable, verifiable, and complete to establish or confirm the MAOPs. The records requirements of §192.205 are not applicable for Type B or C gathering lines (§192.9).

(b) Records may include the following.

- (1) Mill test reports, which might have the following data.
  - (i) Heat numbers.
  - (ii) Steel chemistry.

(iii) Yield strength.
(iv) Ultimate tensile strength.
(v) Pipe grade.
(vi) Pipe wall thickness
(vii) Manufacturing process.

(2) Purchase requisitions and orders.
(3) Bills of lading.
(4) Pressure test records and test procedure documentation.
(5) Pressure rating documentation.
(6) Manufacturing standard(s) documentation.
(7) Manufacturing inspection records.
(8) Coating documentation.
(9) GPS or survey coordinates for the location of installed components.
(10) Construction inspection notes and photographs related to field installation of pipeline components.

(c) Records may be maintained at a central location or at multiple locations for the operational life of the components.
(d) Records may be maintained as paper copies, electronically, or in any other appropriate format.

failure; or

(iii) Cut into at least 3 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.

[Issued by Amdt. 192-34, 44 FR 42968, July 23, 1979 with Amdt. 192-34 Time Ext., 44 FR 50841, Aug. 30, 1979, Amdt. 192-34 Time Ext., 44 FR 57100, Oct. 4, 1979, Amdt. 192-34A, 45 FR 9931, Feb. 14, 1980 and Amdt. 192-34B, 46 FR 39, Jan. 2, 1981; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003; Amdt. 192-94, 69 FR 32886, June 14, 2004; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015]

GUIDE MATERIAL

1 OBSERVATION AND QUALIFICATION OF JOINER

(a) Persons qualifying to make joints in plastic piping should be observed and qualified by a qualified joiner while demonstrating the ability to make satisfactory joints using the correct procedure. See AGA XR0603, "Plastic Pipe Manual for Gas Service."

(b) Confirmation of the ability to make a satisfactory joint requires a visual examination of the specimen joint (see 5 below) and one of the following joint examination options.
   (1) Ultrasonic inspection (see 3 below).
   (2) Destructive testing using methods identified in §192.283(a) (see 4 below).
   (3) Destructive testing as described in §192.285(b)(2)(iii).

2 QUALIFICATION RECORDS

Records or qualification cards or both, which show the extent of the individual's qualifications, including the method of specimen testing, should be maintained for the qualification interval or as needed for OQ compliance purposes.

For transmission pipe projects installed after July 1, 2021, joiner qualification records must be maintained for five years following construction (§192.285(e)).

3 ULTRASONIC INSPECTION OF FUSION JOINTS FOR QUALIFYING JOINERS

Ultrasonic inspection equipment should be capable of inspecting the internal bead for proper formation as well as detecting flaws that would cause failure in the fusion zone. Each manufacturer provides procedures for its equipment as well as training or certification for interpreting results. Each procedure should include the following.

(a) Cleaning the inspection area on both sides of the fusion joint.
(b) Using an appropriate manufacturer-approved couplant to couple the transducer to the pipe.
(c) Inspecting the entire pipe circumference on both sides of the fusion joint.

4 DESTRUCTIVE TESTING OF FUSION JOINTS FOR QUALIFYING JOINERS

Testing methodologies for destructive testing of fusion joints made during qualification of joiners include the following.

(a) ASTM D638 – Standard Test Method for Tensile Properties of Plastics (see §192.7 for IBR for §192.283).
(b) ASTM D2517 – Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings (see §192.7 for IBR for §192.283).
(c) ASTM F1055 – Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing (see §192.7 for IBR for §192.283).
(d) ASTM F2620 - Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings (see §192.7 for IBR).

5 VISUAL INSPECTION FOR PE HEAT FUSION JOINTS FOR QUALIFYING JOINERS

(a) ASTM F2620-20, Heat Fusion Joining of Polyethylene Pipe and Fittings, provides visual examples of successful joints for socket, butt, and saddle fusions. See figures 4 through 6, respectively.
(b) An operator may choose to write its own procedures for qualifying joiners in lieu of using ASTM F2620 (§192.285(b)(2)). The procedures should include the basis for the qualification process and a demonstration that the testing employed provides an equivalent or superior level of safety.

§192.287

Plastic pipe: Inspection of joints.

[Effective Date: 07/14/04]

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.

[Issued by Amdt. 192-34, 44 FR 42968, July 23, 1979 with Amdt. 192-34 Time Ext., 44 FR 50841, Aug. 30, 1979, and Amdt. 192-34 Time Ext., 44 FR 57100, Oct. 4, 1979; Amdt. 192-94, 69 FR 32886, June 14, 2004]

GUIDE MATERIAL

No guide material available at present.

(a) Tracer wire.
   (1) A bare or coated corrosion-resistant metal wire may be buried along the plastic pipe. Wire size #12 or #14 AWG is commonly installed.
   (2) Tracer wire may be installed physically separated from, or immediately adjacent to, the plastic pipe. Separation may lead to difficulty in accurately locating the plastic pipe. In determining placement of tracer wire relative to plastic pipe, the operator should consider the relative importance of locating the pipe versus potential pipe damage from a current surge through the tracer wire. Lightning strikes are a source of current surges.
   (3) Tracer wire should not be wrapped around plastic pipe. It may be taped to the outside of the plastic pipe, especially for installation by boring or plowing-in, or placed loosely in the trench directly adjacent to the pipe.
   (4) A separation of 2" to 6" between plastic pipe and tracer wire is commonly used where current surges, such as from lightning, have been experienced or can be expected.
   (5) Leads from tracer wire into curb boxes and valve boxes and on outside service risers can be used for direct connection of locating instruments. Consideration should be given to ensuring that no bare tracer wire is exposed such that a lightning strike could cause a current surge through the wire.
   (6) Splicing of tracer wire, if necessary, should be done in a manner to produce an electrically and mechanically sound joint that will not loosen or separate under conditions to which it may be subjected, such as backfilling operations and freeze-thaw cycles.
   (7) Where the tracer wire is electrically connected to metallic structures (e.g., steel or cast iron pipe) for reasons such as expanded locating capabilities or cathodic protection, consideration should be given to the effects of electrical current surges on the ability to locate the plastic pipe or the increased potential for damage.
   (8) Additional information may be obtained from AGA XR0603, "Plastic Pipe Manual for Gas Service."
(b) Metallic tape. A metallic coated or corrosion-resistant metallic tape may be installed along with the plastic pipe. Care should be taken so that the tape is not torn or separated during backfilling operations. Metallic locating tape normally has no accessible leads for connecting locating equipment, making it necessary to use a passive or induced current locating device.
(c) Mapping. Accurate mapping of plastic pipe with dimensions referenced to permanent landmarks (e.g., lot lines, street centerlines) is an acceptable method of locating plastic pipe.
(d) Passive devices. Tuned coils or other passive devices may be buried at strategic points along a plastic pipeline. These devices can be located from above ground by means of an associated locating instrument.

2.5 Warning tape.

Highly visible warning tape may be used in addition to one of the means for locating the pipe. Such tapes should be yellow with a safety warning or message, such as "Warning: Buried Gas Pipeline". Warning tapes are generally installed above the plastic pipe so that it will be encountered first by someone digging in the vicinity. For placing warning tape in a ditch, see 3.5 of the guide material under §192.319.

3 PLASTIC PIPE INSERTED INTO A CASING OR INTO AN ABANDONED PIPELINE

3.1 General.
(a) The casing or abandoned pipeline should be prepared to the extent necessary to remove any sharp edges, projections, dust, welding slag, or abrasive material which could damage the plastic during or after insertion. A camera inspection may be performed to assess the conditions inside the casing or abandoned pipeline.
(b) Prior to inserting plastic pipe into an abandoned pipeline, existing offsets, drips, valves that are not full-port, valves that don't fully open, branch connections, obstructions, or projections into the abandoned pipeline should be removed.
(c) Drips, valves, or purges that are abandoned should have their access boxes removed or filled with concrete or other hard-to-remove substance to prevent unintentional damage to the inserted plastic pipe. Purge risers or drip standpipes projecting from the abandoned pipeline should be cut off at, or as near as practicable to, the abandoned pipe. An abandoned valve with plastic pipe inserted through it should be made inoperable.

(d) A support sleeve or plug should be used to prevent the plastic pipe from bearing on the end of the casing or abandoned pipeline.
(e) Methods for closing the leading end of the pipe include the use of a pipe cap or adhesive tape.
(f) The leading-edge cap and piping, and the total length of exposed pipe, should be inspected for damage. If damage is discovered, the pipe should be pulled until an undamaged portion of the pipe is revealed.
(g) Maps or other records should indicate plastic pipe that is inserted in a casing or an abandoned pipeline.
(h) A means of locating inserted plastic pipe should be provided (see 2.4 and 2.5 above).

3.2 Special considerations.

(a) That portion of the plastic pipe which spans disturbed earth should be protected by bridging, by compaction of the soil under the plastic pipe, or by other means to prevent the settling of the backfill from shearing the plastic pipe.
(b) The portion of the plastic pipe exposed due to the removal of a section of casing pipe or abandoned pipeline should have sufficient strength or be protected with bridging or other means, so as to withstand the anticipated external soil loadings.
(c) Protective sleeve installations that are designed to mitigate the stresses imposed onto the plastic pipe in the transition area should be considered if undue stresses are anticipated, or if recommended by the manufacturer. The installation of protective sleeves, in addition to providing adequate backfill and compaction around the transition area, reduces excessive bending and shear stresses. For protective sleeves, see guide material under 192.367.
(d) Cased plastic pipe can contract due to cold gas or low ambient temperature. See 3.5(f) of the guide material under §192.281.
(e) Where a gas leak migrating through the annular space between the plastic pipe and the casing or abandoned pipeline could result in a hazardous condition, consideration should be given to plugging the annular space at one or both ends. Plugs may also be provided at intermediate points, such as where the casing or abandoned pipeline is cut, to permit the installation of a service tee or a lateral main. Care should be used in the selection of the plugging material to avoid damage to the plastic pipe. Both urethane foam and grout have been found to be effective for this purpose.
(f) If water that has accumulated between the casing or abandoned pipeline and the carrier pipe freezes, the carrier pipe can be constricted (affecting the capacity) or damaged causing a leak. One or more of the following steps can be taken to minimize this possibility.
    (1) Sizing the pipe so that the formation of ice between the carrier and the casing or abandoned pipeline will not constrict the carrier pipe to the extent that service is affected.
    (2) Providing for drainage at the lower points in the casing or abandoned pipeline.
    (3) Inserting a filler, such as a closed cell foam material, in the annular space.

3.3 Reference.

See 8 below for plastic pipe encased on bridges.

4 PROVISIONS FOR BENDS

4.1 General considerations.

The bends should be free of buckles, cracks, or other evidence of damage.

4.2 Bending radius.

Plastic pipe may not be deflected to a radius smaller than the minimum recommended by the manufacturer for the kind, type, grade, wall thickness, and diameter of the particular plastic pipe used.

5 SQUEEZE-OFF AND REOPENING THERMOPLASTIC PIPE FOR PRESSURE CONTROL PURPOSES

5.1 Preliminary investigation.

Before thermoplastic pipe is squeezed-off and reopened, investigations and tests should be made to determine that the particular type, grade, size, and wall thickness of pipe of the same manufacture can be squeezed-off and reopened without causing failure under the conditions which will prevail at the time of the squeeze-off and reopening. References for squeeze-off procedures, tools, and precautions are included in the following.

(a) AGA XR0603, "Plastic Pipe Manual for Gas Service."
(b) GRI-92/0147.1, "Users' Guide on Squeeze-Off of Polyethylene Gas Pipes."
(c) GRI-94/0205, "Guidelines and Technical Reference on Gas Flow Shut-Off in Polyethylene Pipes Using Squeeze Tools."
(d) ASTM F1041, "Standard Guide for Squeeze-Off of Polyolefin Gas Pressure Pipe and Tubing."
(e) ASTM F1563, "Standard Specification for Tools to Squeeze-Off Polyethylene (PE) Gas Pipe or Tubing."

5.2 Field consideration.

(a) The work should be done using equipment and procedures that have been established and proven by test to be capable of performing the operation safely and effectively.
(b) If it has been determined by investigation and testing that squeeze-off and reopening affects the long-term properties of the pipe, the squeezed-off and reopened area of the pipe should be reinforced or the pipe segment replaced.
(c) To prevent squeeze-off at the same point, a permanent mark or clamp should be put on the plastic pipe at the location of the squeeze point.

6 DAMAGE PREVENTION

(a) For temporary markings, see 4 of the guide material under §192.319.
(b) For damage prevention considerations while performing directional drilling or using other trenchless technologies, see Guide Material Appendix G-192-6.

7 PLASTIC PIPE TEMPORARILY INSTALLED ABOVE GROUND

7.1 Aboveground exposure to sunlight.

Before using plastic pipe above ground, the operator should obtain the recommended maximum exposure time from the manufacturer and determine the date of manufacture from the Pipe Production Code marked on the pipe. If the operator cannot accurately document the actual time that pipe was stored outdoors, the entire time since the date of manufacture should be considered as aboveground exposure.

7.2 Protection from external forces.

Means to protect the pipe may include:

(a) Barricades.
(b) Fencing.
(c) Elevation support. To prevent strain on the plastic pipe due to sagging or wind forces, elevation support should be provided. A reference for determining support spacing is PPI Handbook of Polyethylene Pipe, Chapter 8, "Above-Ground Applications for Polyethylene Pipe."
(d) Signs and markers.
(e) Physical barriers, such as planks or sleeves.

7.3 Temperature exposure.

Aboveground pipe is exposed to greater variations in temperature than pipe installed below ground. During installation, consideration should be given to pipe elongation and contraction as the temperature changes during the day or seasonally.

7.4 Valves.

Valves installed in aboveground plastic pipe should be braced or anchored, or the adjacent pipe stiffened or reinforced, to decrease torque forces being transferred to the pipe during operation of the valve.

8 PLASTIC PIPE INSTALLED ON BRIDGES

8.1 Design considerations.

The following information for temperature, ultraviolet radiation, external damage, and chemical resistance should be considered when designing plastic pipe systems for installation on bridges.

(a) Temperature.
  (1) Ensure that the hydrostatic design basis (HDB) of the plastic material for the highest temperature anticipated is sufficient to meet the design pressure required by §192.121. Consider heavier-wall plastic pipe or a plastic pipe material with a higher HDB at the anticipated use temperature.
  (2) If the existing HDB is insufficient for the anticipated temperature, consider the potential of both temperature increase and decrease to ensure that the pipeline and joints are adequate for the longitudinal stresses imposed by temperature variations.
  (3) Where the pipeline is installed in a casing, consider installing the pipe in a manner that minimizes thermal effects of heat transfer from the casing to the pipeline and prevents abrasion of the pipe due to thermal expansion and contraction of the plastic pipe. Methods to minimize thermal forces include the following.
    (i) Installation of spacers. The spacers should be placed sufficiently close together to prevent excessive deflection (sag) between the spacers for anchored and guided pipe. Consideration should be given to significant longitudinal stresses when deflection is minimized. Alternatively, the spacers may be placed at a sufficient distance to allow deflection between the spacers to reduce the longitudinal stress. In either case, the amount of deflection should not allow the pipe to contact the casing between spacers. It may be necessary to consider the thermal conductivity of the spacers if they are metallic.
    (ii) Filling the annular space between the pipe and its casing with a tight-fitting insulating material.

(b) Ultraviolet radiation.
  Methods to protect plastic pipe from ultraviolet radiation include the following.
  (1) Installation of pipe within a casing.
  (2) Use of compatible external coating on the pipe.

(c) External damage.
  (1) Position the pipeline to protect it from external damage. Consider providing additional protection, such as installation in a casing or utility tunnel.
  (2) Where installed in a casing, the pipeline should be protected from shear forces imposed by soil or other loading at the ends of the casing.

(d) Chemical resistance.
  Consider the installation environment (e.g., salts used on roads during winter, vehicle oils), and ensure that the plastic pipe is adequate for the exposure.

8.2 Other considerations.

(a) Other regulations. The agency having jurisdiction over the bridge should be consulted to determine if there are additional requirements.
(b) Casing end seals. Consider the installation of casing end seals to prevent water from entering the annular space between a casing and the pipeline.
(c) Valves. Consider installing valves to isolate the pipe on the bridge in case of a leak or failure.
(d) Seismic. Consider the effects of abnormal movement in areas of seismic activity.
(e) Joints. Butt fusion, electrofusion, or ASTM D2513 (see §192.7) Category 1 mechanical fittings should be used. However, Category 2 or Category 3 mechanical fittings may be used provided their joining procedure includes additional restraint as needed to meet the pullout requirements of §192.283(b).

8.3 References.

(a) ASME I00353, "Installation of Plastic Gas Pipeline in Steel Conduits Across Bridges."
(b) PPI Handbook of Polyethylene Pipe, Chapter 8, "Above-Ground Applications for Polyethylene Pipe."

9 INSTALLATION OF PA-11 or PA-12 PIPING FOR HIGHER PRESSURE APPLICATIONS

If PA-11 or PA-12 piping is installed for operating pressures up to and including 125 psig, standard installation procedures may be used. If pressures exceed 125 psig, the following guidance should be considered.

9.1 Installation.

In addition to a method of locating (see 2.4 above), consider using a highly visible yellow warning tape (see 2.5 above) with a legend, such as "WARNING: Buried High Pressure Plastic Gas Pipeline."

9.2 Pressure tests.

Safety precautions similar to those used during other higher pressure pipeline tests should be employed due to the higher operating and test pressures for PA-11 or PA-12 piping. For example, PA-11 pipelines with an intended MAOP of 200 psig are required to be tested at 300 psig per §192.619(a)(2)(i).

9.3 Hot taps.

Currently, only mechanical or electrofusion hot-tapping tees are recommended for use on PA-11 or PA-12 piping. To avoid a blow-out when making hot taps using fusion fittings, the pressurized pipeline should not be heated above the manufacturer's recommendations. Consult the manufacturer for the appropriate hot-tapping joining method recommendations. See 3 of the guide material under §192.123.

§192.323

Casing.

[Effective Date: 11/12/70]

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.

GUIDE MATERIAL

(a) Where plastic piping must be cased or bridged, suitable precautions should be taken to prevent crushing or shearing the piping. See guide material under §192.321.

(b) A reference for the design, installation, maintenance, repair, and monitoring of steel-cased pipelines is NACE SP0200, "Steel-Cased Pipeline Practice."

§192.325

Underground clearance.

[Effective Date: 07/13/98]

(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).

[Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL

1 CLEARANCE

1.1 Transmission lines (§192.325(a)).

If a minimum of 12 inches of clearance cannot be attained at the time of installation, less clearance may be allowed provided:

(a) Adequate measures are undertaken to prevent contact between the pipeline and the underground structure, such as encasement of the pipeline with concrete, polyethylene or vulcanized elastomer, or the installation of sand-cement bags, concrete pads or open-cell polyurethane pads in the space between the pipeline and the underground structure.

(b) Adequate measures are taken to prevent mechanical damage to the pipe and coating of multiple pipeline bundles installed by directional boring. Adequate measures should be employed to provide separation between the individual pipelines in the bundle in order to minimize damage to the pipe and coating. This may be accomplished by employing dielectric spacing devices (e.g., dense rubber spacers) or vulcanized elastomer spacers between the individual pipelines in the bundle. See §192.461(e).

1.2 Mains (§192.325(b)).

The following possible activities should be considered when determining the clearance to be attained between the main being installed and other underground structures.

(a) Installation and operation of maintenance and emergency control devices, such as leak clamps, pressure control fittings, and squeeze-off equipment.

(b) Connection of service laterals to both the main and other underground structures.

(c) For additional methods of protection in lieu of sufficient clearance, see 1.1(a) above.

1.3 Clearance between plastic main or transmission line and any source of heat (§192.325(c)).

The operator should consider the degree of the hazard presented by the heat source when determining the clearance, insulation, or protective material. For installations near electric or steam lines, the operator should also consider the following.

(a) A minimum radial separation of 12 inches is recommended by the Common Ground Alliance's "Best Practices" Guide, Practice Statement 2.12, available at https://commongroundalliance.com/best-practices-guide. See 5.3(d) of the guide material under §192.361.

(b) For installations near electric lines, see 5.3(e) of the guide material under §192.361.

2 ADJACENT UNDERGROUND STRUCTURES

When installing new mains or replacing existing mains, the proximity and condition of existing conduits, ducts, sewer lines, and similar structures, including abandoned structures, should be considered since they have the potential to provide a path for the migration of leaking gas.

§192.327
Cover.

[Effective Date: 09/09/04]

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

Location	Normal soil 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).

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

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

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

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

[Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-98, 69 FR 48400, Aug. 10, 2004]

GUIDE MATERIAL

See Guide Material Appendix G-192-13.

§192.328

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

[Effective Date: 12/22/08]

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 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.**

[Issued by RIN 2137-AE25, 73 FR 62148, Oct. 17, 2008; Eff. date stayed by 73 FR 72737, Dec. 1, 2008]

Guide Material

1 GENERAL REQUIREMENTS

(a) If a new or existing steel pipeline meets the additional construction requirements of §192.328, it may be eligible for operation at an alternative maximum allowable operating pressure (MAOP) as determined under §192.620.
(b) A greater level of quality assurance is required for additional construction requirements if an alternative MAOP is to be permitted (§192.328(a)). Each additional construction requirement should be addressed in a quality assurance plan.

2 QUALITY ASSURANCE

(a) For this guide material, quality assurance is an overall process to ensure and document that the pipeline construction elements identified in §192.328(a)(1) are done in a manner that will not compromise future integrity.
(b) Quality assurance for pipeline construction might consist of the following core elements.
  (1) Identifying the needed processes, which must include those elements listed in §192.328(a)(1).
  (2) Determining the process sequence and interaction.
  (3) Determining the criteria which will be measured or tracked and a methodology that will be used to ensure that process acceptance is within tolerance limits.
  (4) Identifying the necessary resources for the operation and monitoring of the processes, including a skill and knowledge assessment for the personnel.
  (5) Monitoring, measuring, and analyzing processes during pipeline construction and reviewing the effectiveness of those processes.
  (6) Implementing actions to achieve required project results and to have continuing improvement in the individual processes.
  (7) Identifying and maintaining records and support documentation that should be retained. These records might be part of the ongoing evaluations in the operator's Integrity Management Program or be associated with the conditions of a special permit (waiver) required by PHMSA-OPS under §190.341(d)(2).
  Note: A "special permit" was previously referred to as a "waiver" by PHMSA-OPS. State terminology may differ (e.g., wavier, variance).
(c) Quality assurance processes can use new procedures or existing procedures as modified, and should be measurable to determine performance.

3 FIELD-APPLIED COATINGS

3.1 General.
Fusion-bonded, two-part epoxy coatings, or three-layer coatings may be used to coat girth welds during the construction of new transmission pipelines with an alternative MAOP. Coating defects with these field-applied coatings may be caused by the following.
(a) Failing to follow manufacturer's instructions or operator's procedures.

(b) Improper cleaning (e.g., coating over mud, debris, condensation, rust).
(c) Inadequate surface preparation.
(d) Abrasive blast technique – lack of correct bevel or no overlap at factory coating.
(e) Inadequate mixing of the epoxy.
(f) Application temperature too hot or cold.
(g) Heat damage to the factory fusion bonded epoxy (FBE) coating.
(h) Water in the pipe during heating, which prevents uniform heating.
(i) Coating in high wind with blowing dirt.
(j) Girth weld coating not fully bonded to pipe.
(k) Inadequate skills or technique.

3.2 Pipe surface preparation standards.

Pipe surface preparation is required to get the needed pipe surface profile for a field-applied coating. This includes abrasive blasting, achieving the required coating cutback, and, if required, pre-heating the girth weld area to get the required surface temperature in accordance with the coating manufacturer's specifications. In addition to the manufacturer's installation instructions, standards from the following organizations may be used as guidelines for preparing the pipe surface for field-applied coatings.
(a) The Society for Protective Coatings (SSPC).
(b) National Association of Corrosion Engineers (NACE).

3.3 Application method.

(a) Spray.
(b) Brush.
(c) Roller.

3.4 Environmental considerations.

(a) Air and pipe surface temperatures.
(b) Relative humidity and dew point.
(c) Presence of precipitation or condensation.
(d) Other factors, such as wind.

3.5 Coating application considerations.

(a) Adherence to coating thickness requirements and verification measurements.
(b) Minimum cure times for liquid and dry powder applications.
(c) Adherence to manufacturers' application instructions, especially with liquid coatings.
(d) Visual coating inspection before lowering pipe into ditch to identify the following.
  (1) Runs.
  (2) Drips.
  (3) Blisters.
  (4) Foreign inclusions.
  (5) Insufficient overlap on tape and shrink sleeve applications.
  (6) Insufficient dry-film thickness.

4 COATING INSPECTION AND HOLIDAY TESTING

Prior to backfilling, the coating of the entire pipeline should be visually inspected by trained inspectors. This visual examination might be supported with the use of a holiday detector (jeep) to detect coating anomalies or imperfections. Coating integrity could be compromised if the following procedural errors occur when jeeping.
(a) Failing to adequately clean the pipe before jeeping.
(b) Using personnel and inspectors without adequate training.
(c) Failing to follow manufacturer's instructions for holiday detector.
(d) Using a detector that was not calibrated per manufacturer's specifications.
(e) Using damaged (bent) or dirty detector springs.

(f) Using incorrect voltage setting on detector.
(g) Jeeping too fast.
(h) Jeeping with high resistance in electrical circuit.
(i) Jeeping over debris (e.g., tape, fiberboard) stuck to the pipe.
(j) Jeeping over coating repairs before they are dry.

5 NONDESTRUCTIVE TESTING OF GIRTH WELDS

(a) All girth welds of a new pipe segment operating at an alternative MAOP must be nondestructively tested (§192.328(b)).
(b) Defects at girth welds could be caused by the following procedural errors during the welding process.
    (1) Incorrect welding procedure used.
    (2) Incomplete weld procedure qualification.
    (3) Lack of inspector oversight.
    (4) Improper joint fit-up.
    (5) High-low pipe alignment issues.
    (6) Improper storage of low hydrogen rods.
    (7) Improper welding electrode selection.
    (8) Incorrect pre-heat or interpass temperature.
    (9) Premature alignment clamp release.
    (10) Arc burns due to poor welding practices.
    (11) Inadequate visual weld inspection.
    (12) Improper diffusion of hydrogen during welding process.
    (13) Rapid cooling of weld.
(c) For additional guidance, see guide material under §§192.243 and 192.620.

6 DEPTH OF COVER

(a) A minimum depth of 36 inches or equivalent means to protect the pipeline from outside force damage is required for pipeline segments operating at an alternative MAOP (§192.328(c)).
(b) For additional guidance on depth of cover and equivalent means to provide protection from outside forces, see Guide Material Appendix G-192-13.
(c) Depth of cover should be noted in construction records.

7 INITIAL STRENGTH TESTING

(a) A root-cause analysis is required for any initial strength testing failure on a pipeline that is being constructed to operate at an alternative MAOP to determine whether systemic material defects are present (§192.328(d)).
(b) A root-cause analysis could have the following core elements.
    (1) Definition and scope of material issue.
    (2) Data gathering.
    (3) Threat assessments.
    (4) Supporting investigations.
    (5) Root-cause determination.
    (6) Recommendations and their implementation.
    (7) Monitoring.
(c) For additional guidance on strength testing, see guide material under §§192.503, 192.505, and 192.620, and Guide Material Appendix G-192-9.

8 INTERFERENCE CURRENTS

See guide material under §§192.455 and 192.473.

9 RECORDS

(a) Records demonstrating compliance with the additional construction requirements for an alternative MAOP must be maintained for the useful life of the pipeline (§192.328). These records might include the following.
  (1) Material specifications.
  (2) Construction specifications.
  (3) Welding specifications and procedures.
  (4) Bills of lading or shipping manifests.
  (5) Daily construction inspection reports and documentation.
  (6) Photographs of construction activities.
  (7) Nondestructive testing reports.
  (8) Bending calculations.
  (9) Fabrication and as-built drawings.
  (10) Cathodic protection documentation.
  (11) Test charts or electronic testing logs.

(b) Records may be kept in a variety of formats that include the following.
  (1) Paper.
  (2) Work management systems.
  (3) Geographic information system (GIS).
  (4) Other electronic databases.

§192.329

Installation of plastic pipelines by trenchless excavation.

[Effective Date: 01/22/19]

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.

[Amdt 192-124, 83 FR 58694, Nov. 20, 2018]

GUIDE MATERIAL

GENERAL REQUIREMENTS

(a) See Substructure Damage Prevention Guidelines for Directional Drilling and Other Trenchless Technologies under Guide Material Appendix G-192-6.

(b) See weak link guide material under Guide Material Appendix G-192-15B, Section 5.

lines. This may cause the flow to exceed the minimum trip point of the EFV, thus causing it to close.

4 INSTALLATION CONSIDERATIONS

The manufacturer's recommended procedures for installation of an EFV should be followed unless the operator establishes alternative procedures based on sound engineering considerations. The following are some general installation factors for consideration. Also, see guide material under §192.383 that addresses different examples.

4.1 *Farm taps.*
For some installations, two-stage pressure regulation is used where a high pressure line (e.g., transmission line) is the source of supply. An operator may choose to install a second EFV upstream of the first-stage regulator, if desired, for protection of the high pressure portion of the line.

4.2 *Contaminants.*
During or prior to installation, foreign material (e.g., dirt, liquid, plastic pipe shavings) should be removed from the service line to prevent contaminants from entering the EFV.

4.3 *Gas flow direction.*
Ensure the EFV is properly oriented with the direction of gas flow.

4.4 *Application of heat.*
Exposure to heat when performing such tasks as tie-ins or coating applications should be controlled to avoid adversely affecting the EFV. To prevent damaging the mechanism, care should be taken on steel installations to keep welding heat away from the EFV. In some circumstances, a wet rag may be placed over the steel nipple housing the EFV when the valve is being welded in place. Otherwise the steel nipple housing the EFV should be of appropriate length to allow necessary weld heat dissipation.

4.5 *Pressure testing.*
When performing a pre-installation pressure test through the upstream lateral tee, a rapid re-pressurization of the line should be avoided because such action might damage or close the downstream EFV.

4.6 *Post-installation activation test.*
After installation, consider testing the EFV to ensure that it trips and then resets. To test, trip the EFV by venting the service line to atmosphere. Then, follow the manufacturer’s reset procedure.

4.7 Purging a service line.
Care should be taken to avoid excess flow that would cause the EFV to close. Techniques to avoid closure include opening the meter valve slowly, using an orifice cap, or purging the service line through the regulator.

5 IDENTIFICATION CONSIDERATIONS

Marking and identifying that an EFV has been installed may be accomplished by one or more of the following.
(a) Affixing a durable identifying tag to the exposed portion of the gas riser or meter set.
(b) Indicating the presence of an EFV on maps or records.
(c) Using GPS coordinates.
(d) Using a passive electronic marker.
(e) Other methods.

(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.

[Issued by Amdt. 192-83, 63 FR 5464, Feb. 3, 1998 with Amdt. 192-83 Correction, 63 FR 20134, Apr. 23, 1998; Amdt. 192-113, 74 FR 63906, Dec. 4, 2009 with Amdt. 192-113 Correction, 75 FR 5244, Feb. 2, 2010; Amdt. 192-116, 76 FR 5494, Feb. 1, 2011; Amdt. 192-121, 81 FR 70987 Oct. 14, 2016 with Amdt. 192-121 Correction, 81 FR 72739, Oct. 21, 2016]

GUIDE MATERIAL

1 EXCESS FLOW VALVES (EFV) INSTALLATIONS

1.1 General.

Unless one or more of four conditions listed in §192.383(c) is present (service line does not operate at a pressure of at least 10 psig throughout the year, contaminants in the gas stream could interfere with the EFV's operation or cause loss of service to the customer, EFV could interfere with required operation or maintenance activities such as blowing liquids from the line, or an EFV is not commercially available for the application), §192.383 requires an EFV to be installed at the time of installation of new or replaced service lines that serve the following.

(a) A single-family residence.
(b) A single-family residence on a branched service line that is installed concurrently with the primary single-family residence service line. A single EFV may be installed to protect both the primary and the branched service lines.
(c) A single-family residence, that is branched from an existing service line that does not have an EFV.
(d) A multi-family residence with a total meter capacity not exceeding 1,000 SCFH for the service line.
(e) A single, small commercial customer with meter capacity not exceeding 1,000 SCFH.

The EFV installation requirements of §192.383 and the manual service line shut-off valve (MSLV) installation requirements of §192.385 are summarized below in Table 192.383i.

SUMMARY OF EXCESS FLOW VALVE (EFV) AND MANUAL SERVICE LINE SHUT-OFF VALVE (MSLV) INSTALLATION REQUIREMENTS					
	Single-Family Residences[1]	Multifamily Residences		Commercial Customers Served by a Single Service Line	
	Any Meter Capacity	Installed Meter Capacity ≤ 1,000 SCFH	Installed Meter Capacity > 1,000 SCFH	Installed Meter Capacity ≤ 1,000 SCFH	Installed Meter Capacity > 1,000 SCFH
Operating Pressure < 10 PSIG	Nothing Required	Nothing Required	Install MSLV	Nothing Required	Install MSLV

Operating Pressure ≥ 10 PSIG	Install EFV[2]	Install EFV[2]	Install EFV or MSLV	Install EFV[2]	Install EFV or MSLV

Source: PHMSA Excess Flow Valve FAQs May 17, 2022
[1] Includes both single service lines and branched service lines for single-family residences.
[2] Subject to exceptions listed in §192.383(c).

TABLE 192.383i

1.2 Service line supplying a single-family residence.

As required by §192.383(b)(1) and except for the limitations of §192.383(c), an operator must install an EFV on a new or replaced service line to a single-family residence. The following illustrations (Figures 192.383A and 192.383B) show where an EFV should normally be installed on a service line to a single-family residence to comply with §192.381(d). For other EFV installation considerations, see guide material under §192.381.

EFV with Meter Located at Residence

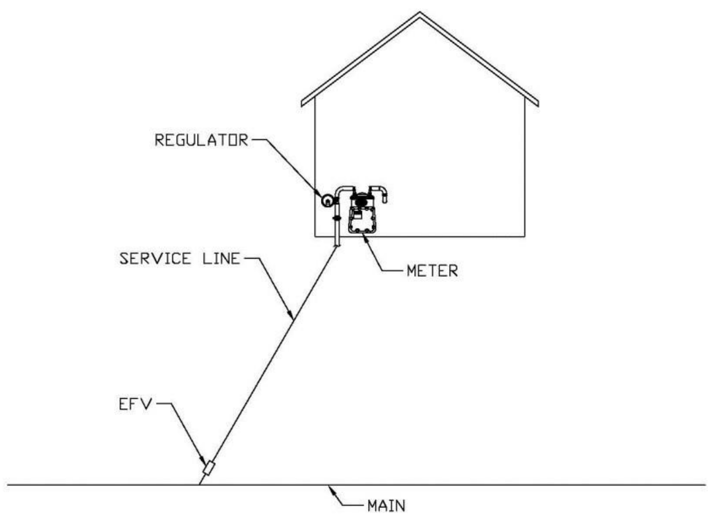


FIGURE 192.383A

or other personnel authorized by the operator, to manually shut off gas flow to the service line, if needed. The manual service line shut-off valve described in this section does not refer to the riser valve or the meter shut-off valve at the meter set assembly located at the building where the service line terminates.

1.2 Installation.

Section 192.385 requires an operator to 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 capacities exceeding 1,000 SCFH. A manual service line shut-off valve should be located near the service main or a common source of supply to protect as much of the service line as is practicable.

Notes:

(1) The installation of a manual service line shut-off valve on a service line to single family residence (SFR) or branched service line to an SFR, regardless of installed meter capacity, does not satisfy the requirement to install an EFV under §192.383.

(2) The exceptions listed under §192.383(c) for the installation of an EFV do not apply to a manual service line shut-off valve.

(3) Refer to Table 192.383i titled, "Summary of Excess Flow Valve (EFV) and Manual Service Line Shut-Off Valve (MSLV) Installation Requirements" in the guide material under §192.383.

1.3 Accessibility and Maintenance

A manual service line shut-off valve (e.g., curb valve) installed in accordance §192.385 must be installed in such a manner that it will be accessible in an emergency. This valve is subject to regularly scheduled maintenance consistent with the valve manufacturer's specification (or as specified by the operator if the manufacturer provides no specification), and the valve is to be accessible and operable. This maintenance may occur in conjunction with other activities when qualified personnel are present (e.g., meter-change programs, patrolling, leak surveys, activities where the service would be shut off). These valve maintenance requirements do not apply to valves that are installed in addition to an EFV.

(i) Unintended closure of valves or shutdowns;
(ii) Increase or decrease in pressure or flow rate outside normal operating limits;
(iii) Loss of communications;
(iv) Operation of any safety device; and
(v) Any other foreseeable malfunction of a component, deviation from normal operation, or personnel error, which may result in a hazard to persons or property.

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

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

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

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

(d) *Safety-related condition reports.* The manual required by paragraph (a) of this section must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of §191.23 of this subchapter.

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

[Amdt. 192-27A, 41 FR 47252, Oct. 28, 1976; Amdt. 192-59, 53 FR 24942, July 1, 1988 with Amdt. 192-59 Correction, 53 FR 26560, July 13, 1988; Amdt. 192-71, 59 FR 6579, Feb. 11, 1994 with Amdt. 19271A, 60 FR 14379, Mar. 17, 1995; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003; Amdt. 192-112, 74 FR 63310, Dec. 3, 2009]

GUIDE MATERIAL

Note: Although not required, operators should consider establishing a procedural manual for Type B gathering lines.

1 GENERAL

(a) Each procedural manual for operations, maintenance, and emergencies should include a written statement, procedure, or other document addressing each specific requirement of §192.605 that applies to the operator's pipelines. The requirements of §192.605 are included in paragraphs that cover the following topics.
   (1) General items related to the procedural manual (§192.605(a)).
   (2) Maintenance and normal operation of any pipeline (§192.605(b)).
   (3) Abnormal operation of transmission lines, other than those transmission lines operated by distribution operators in connection with their distribution system (§192.605(c)).
   (4) Safety-related condition reports (§192.605(d)).
   (5) Surveillance, emergency response, and accident investigation (§192.605(e)).

   The guide material under this section addresses most of the requirements of §192.605.

(b) The comprehensive manual can consist of multiple binders with relevant sections kept at appropriate locations. Appropriate sections of other documents may be referenced instead of being incorporated, but the referenced documents are to be present at the location to which they apply.

(c) The manual will necessarily vary in length and complexity depending upon the individual operator, its size, locale, policies, and types of equipment in use and the amount of material included in its entirety or cross-referenced, including manufacturers' instructions, where appropriate.

(d) Procedures for only those facilities within the operator's system need be included in the manual.

Therefore, it is not necessary to have a manual for each pipeline.

(e) The required review of the manual should ensure that the operator's current facilities and any deficiencies in the manual are addressed. Applicable manual contents and updates to the manual should be communicated as soon as practicable to operator personnel and contractors affected by the change. This communication may occur at the time of employment, prior to contractor job mobilization, prior to work, and after any supplemental updates to the manual are implemented.

(f) An operator should consider reviewing its operator qualification (OQ) processes and procedures since changes to the manual may affect the OQ program. More serious deficiencies, possibly identified following an accident, may require immediate correction.

(g) Many sections of the pipeline safety regulations are written using performance language to achieve a desired result, but the method to reach that result is not specified. In such situations, an operator should use a method that is suitable for its individual operations and include it in the manual.

(h) An operator may include material in its procedural manual for operations, maintenance, and emergencies that is not required by the federal or state pipeline safety regulations (e.g., procedures for the use of personal protection equipment, procedures regarding the aesthetic acceptability of paint on aboveground piping). Even though such procedures themselves are supplementary to the procedures required by the pipeline safety regulations, they may be subject to inspection or enforcement by pipeline safety inspection agencies. The operator may consider identifying such procedures as not being part of the manual for operations, maintenance, and emergencies that is required by §192.605.

(i) An operator may define in its manual a process to address situations in which a procedure cannot be followed in its entirety. That process should include the requirement for a written request and approval for a variance from the procedure, the level of authority that can approve a variance, and record-retention requirements. The operator should ensure the effect of the approved variance from the procedure still meets the minimum regulatory requirements.

(j) See guide material under §§192.491, 192.603, 192.709, and Guide Material Appendix G-192-17 for additional information on record retention and security.

2 MAINTENANCE AND NORMAL OPERATIONS

In addition to those items required to be in the manual under Subparts L and M as they apply to the operator's facilities, other Subparts (e.g., E, F, I, J, and K) may also require written procedures. Additional guide material can be found under individual sections.

2.1 *Control of corrosion.*

Refer to guide material for respective sections of Subpart I.

2.2 *Availability of construction records, maps, and operating history.*

(a) Construction records, maps, and operating history should be comprehensive and current. The construction records, maps, and operating history will depend upon the individual operator, its size and locale, and the types of equipment in use. See guide material under §192.227 for records demonstrating the qualification of each individual welder at the time of construction.

(b) The construction records, maps, and operating history should be made available to operating personnel, especially supervisors or those called on to safely operate pipeline facilities or respond to emergencies, or both. Dispatch or gas control personnel should have maps and operating history available.

(c) For transmission and regulated gathering facilities, the types of records and data that could be made available are as follows.
  (1) Pipeline system maps, including abandoned and out-of-service facilities.
  (2) Compressor station and other piping drawings (mechanical and major gas piping).
  (3) Maximum allowable operating pressures.
  (4) Inventories of pipe and equipment.
  (5) Pressure and temperature histories.
  (6) Maintenance history.
  (7) Emergency shutdown systems drawings.
  (8) Isolation drawings.

(9) Purging information.
(10) Applicable bolt torquing information.
(11) Operating parameters for engines and equipment.
(12) Leak history.

(d) For distribution systems, the types of records and data that could be made available are as follows.

eliminated.

(d) Shutting down a pipeline.
See Guide Material Appendix G-192-12.

(e) Abandoning a pipeline after it is shutdown.
See guide material under §192.727.

2.5 *Maintaining compressor stations.*

During normal maintenance activities, the following should be considered and applied where appropriate.

(a) Provisions should be made to prevent gas from entering the compressor cylinders of a reciprocating engine or a compressor case of a centrifugal compressor while work is being performed on the units. These provisions should also include the deactivation of the valve operators.

(b) Provisions should be made to prevent fuel gas from entering the power cylinders of a reciprocating engine or the burner cans of a gas turbine while work is in progress on the unit or equipment driven by the unit.

(c) Provisions should be made to prevent starting air from entering the power cylinders of a reciprocating engine and to prevent starting air or gas from entering any other starting device on an engine or turbine while work is in progress on the unit or equipment driven by the unit. The flywheel of the reciprocating engine should be locked in a stationary position where possible.

(d) Recommended methods for isolating the units from sources of gas or starting air include installation of a blind flange, removal of a portion of the supply piping, or locking a stop valve closed and locking a downstream vent valve open. If a common downstream vent is used, provision should be made to prevent backflow to the units.

(e) Provisions should be made to prevent energizing the electric circuits of a motor driven or motor started compressor unit while work is in progress on the unit or on equipment driven by the unit.

(f) See 2 and 3 of the guide material under §192.147 for bolting information.

(g) Provisions should be made to return the equipment to service in an orderly manner to prevent the uncontrolled release of gas to the atmosphere, or overpressuring an isolated or purged piece of equipment or section of pipe.

2.6 *Starting, operating, and shutting down gas compressor units.*

The procedures for the starting, operating, and shutdown of gas compressor units should be in writing and may be developed from operating experience, direct use of manufacturers’ instruction manuals, or a combination of both.

2.7 *Periodically reviewing the work done by operator personnel.*

Field oversight including supervisor visits, field inspections, and quality control are some of the methods available to periodically review the work done by operator personnel. The operator should designate a timetable to review personnel performance to determine if the normal operating and maintenance procedures found in the manual are effective and adequate. The operator should determine if deficiencies exist in the procedures. If applicable, modification of procedures should be accomplished as soon as possible. Documentation should be maintained for all procedure modifications and retraining of personnel.

2.8 *Taking precautions in excavated trenches to protect personnel.*

Personnel working in or near a trench should be aware of the potential for an oxygen-deficient environment and of potential dangers from accumulations of gas or vapor, particularly those associated with liquid petroleum gases. When determining the likelihood of gas or vapors presenting such a hazard to personnel, the operator should consider the depth and configuration of the trench, the product transported, and the diameter, pressure, type of piping material, condition, and configuration of the pipeline facilities. Although natural gas is lighter than air and non-toxic, some gas pipelines contain constituents such as hydrogen sulfide, heavier-than-air hydrocarbons, and hydrocarbon liquids that may present a hazard to personnel working in or near the trench. The operator should establish criteria for what constitutes a hazardous condition, taking into consideration the LEL of the gas involved. Escaping gas may present an added hazard because of the displacement of oxygen. An

See guide material under §§192.631(f) and 192.911(k) for more information on MOC.

3 ABNORMAL OPERATION OF TRANSMISSION LINES

3.1 General.

(a) The abnormal operation requirements in §192.605(c) do not apply to distribution operators that are operating transmission lines in connection with their distribution system (§192.605(c)(5)).

(b) An abnormal operation is an event on a gas transmission or Type A gathering facility that occurs when operations are outside the normal limits. When an abnormal operation occurs, it does not pose an immediate threat to life or property, but could if not promptly corrected. Where applicable, the actions to be taken by the transmission operator in each situation should incorporate the current procedures. The procedures should be specific enough to ensure uniformity of action relative to the situation, such as those referenced above, while allowing sufficient flexibility to consider the particular details, material, equipment, and configurations involved.

(c) Where applicable, the actions to be taken by the transmission operator in each situation should incorporate current procedures. The procedures should be specific enough to ensure uniformity of action relative to the situation while allowing sufficient flexibility to consider the particular details, material, equipment, and configurations involved.

(d) The term “abnormal operating condition” relates to the Operator Qualification requirement that personnel can recognize and react to abnormal operating conditions. See guide material under §192.803 for more information.

Note: A condition can be both an abnormal operation under §192.605(c) and an abnormal operating condition under §192.803.

3.2 Types of abnormal operations.

Descriptions of types of abnormal operations could include the following.

(a) Unintended closure of valves or shutdowns could include the following.
- (i) Automatic valves.
- (ii) Flow reducing valves.
- (iii) Failure to reopen or to close after routine maintenance.
- (iv) Vandalism.

(b) Increase or decrease in pressure or flow rate outside normal operating limits.
- (i) Operator should define the source or basis for “normal operating limits”, and could include engineering design basis, SCADA set points.
- (ii) Examples include flow that decreases where customer service cannot be maintained, or overpressure events.
- (iii) Temperature, high or low.

(c) Loss of communications should be defined by the operator based on communication methods in use to ensure safe operation, which may include the following.
- (i) A SCADA outage, which may require manning of normally unmanned stations. The operator might consider defining a period of time to restore these communications prior to declaring an abnormal operation.
- (ii) Backup communications systems, if the outage requires manning assets or stations, such as the following.
  - A. Telephone service (wired).
  - B. Cell phone service.
  - C. Radios (portable).

(d) Operation of safety devices used to protect pipeline pressure, including the following.
- (i) Relief device.

(ii) Noticeable operation of a monitor regulator.
(iii) Compressor engine shutdowns due to pressure deviation.
(iv) Operation of slam shuts.

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

3.3 *Considerations for abnormal operations.*

When developing response procedures for abnormal operations, the transmission operator should consider the following.

(a) Type of event. See list under 3.2 above.
(b) Proximity of the event to the public.
(c) Potential for the event to become an emergency situation if not immediately corrected.
(d) Effect of the event on the pipeline system.
(e) Notification of appropriate operator personnel regarding the abnormal operation.
(f) If Documentation of the abnormal operations, including any relevant information regarding the discovery and confirmation of the event. This may include the following.
    (i) Operational information (including SCADA readouts) that confirms the event (e.g., pressure readings, indications of valve closure, flow rates, control room log books indicating loss of communication, other relevant information).
    (ii) Photos of affected equipment.
    (iii) Names of personnel identifying and responding to abnormal operations events.
    (iv) Abnormal Operations forms completed with above information.
(g) Documentation of the response actions taken.
(h) If the event is an increase in pressure outside normal operating limits, the potential for MAOP plus allowable buildup to be exceeded. See 4.4(f) below and (d) of the guide material under §191.23.
(i) Consider the need to communicate abnormal operation information to integrity management personnel for threat consideration.
(j) Determine if a failure investigation of equipment is needed in accordance with the requirements of §192.617.

3.4 *Return to normal operations criteria and verification.*

(a) The extent of follow-up monitoring should be based on the nature of the event and the probability that the cause of the event could recur. This should include checking variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation.
(b) The abnormal operation is considered corrected when an operator determines, at the end of the monitoring period, that the pipeline facility has maintained operations within its operating design limits and is capable of safely operating up to its MAOP.
(c) Actions to consider to confirm return to normal operations readiness.
    (i) Notify field operations and maintenance personnel to be alert to signs of leakage or damage to pipeline facilities.
    (ii) Notify control room personnel, so they can more closely monitor facilities.
    (iii) Conduct and document right-of-way patrol of the affected pipeline segment.
    (iv) Conduct and document leak survey of the affected pipeline segment.
    (v) Conduct and document inspection of overpressure protection devices for signs of activation. Determine if the devices activated as expected and at the correct pressures.
    (vi) Determine probable cause or conduct failure analysis; share results with appropriate personnel. For guidance on performing a failure investigation, see guide material under §192.617.
    (vii) Ensure integrity management personnel are informed so this event and associated data can be considered in future risk analyses.

(viii) Review procedural manual, operator qualification program, control room management procedures, and other written procedures for any needed revisions, per 3.6 below.

3.5 Preventing recurrence of abnormal operation.

Once the event has been investigated, and normal or safe operations have been restored, the operator should determine what measures can be taken to prevent the cause of the event from recurring. The operator should also consider whether these measures should be implemented elsewhere in the transmission system to avoid similar occurrences of abnormal operation.

3.6 Review of response activities.

Response activities should be reviewed based on the extent of the abnormal operation. The review should consider the actions taken and whether the procedures followed were adequate for the given situation or should be revised to provide more specificity or more flexibility. Response activity reviews can include various processes. The specific processes followed should be based on the extent and type of abnormal operations and can include the following.

(a) Root cause analysis.
(b) Post-event reports.
(c) Tailgate or safety meeting discussions.
(d) Near-miss and accident investigation analysis.
(e) Simulation or event reconstruction reviews.
(f) Drills or other exercises.

3.7 Documentation

Depending on the circumstances and extent of the event, documentation after abnormal operations can include the following.

(a) Event details and completed forms or information verifying abnormal operations.
(b) Any post-event O&M activity to confirm the condition no longer exists and that normal operations can resume, such as leak surveys, ROW patrols, or inspection of overpressure protection devices.
(c) Root cause or failure analysis.
(d) Lessons learned.
(e) Meeting notes and other communication regarding identification and response.
(f) Manual and procedure reviews completed as a result of the abnormal operations.

4 POTENTIAL SAFETY-RELATED CONDITIONS, ANALYSIS, AND ACTIONS

4.1 Potential safety-related conditions.

Personnel who perform O&M activities should recognize the following anomalies as potential safety-related conditions that may be subject to the reporting requirements of §191.23.

Note: Reporting requirements for (a), (b), and (d) below apply to a pipeline that operates at 20% or more of SMYS.

(a) General corrosion that has reduced the pipe wall thickness to less than that required for the MAOP.
(b) Localized corrosion pitting which has progressed to a degree where leakage might result.
(c) Unintended movement or abnormal loading by environmental causes (e.g., earthquake, landslide, subsidence, flood) that impairs the serviceability of a pipeline segment.
(d) Material defects, such as those caused in the manufacturing process, or physical damages that impair the serviceability of a pipeline segment. Sound engineering criteria should be used to determine if an observed condition involving a material defect or physical damage impairs serviceability.
(e) Malfunctions or operating errors that cause the pressure of a pipeline to rise above its MAOP plus the buildup allowed for the operation of pressure limiting or control devices

(f) Pipeline leaks that constitute the need for immediate corrective action to protect the public or property. Examples include leaks occurring in residential or commercial areas in conjunction with a natural disaster; leaks where a flammable vapor is detected inside a building; and leaks that involve response by police or fire departments. While venting is done to mitigate an unsafe condition, it does not remove the unsafe condition.

(g) Other known anomalies or events that could lead to an imminent hazard and cause (either directly or indirectly by remedial action of the operator) for purposes other than abandonment, a 20% or more reduction in operating pressures or shutdown of operation of the affected pipeline segment

4.2 Procedures and guide material used to recognize a potential safety-related condition.

Personnel who perform O & M activities may use O & M procedures written in compliance with Subparts I, L and M and the associated guide material and guide material appendices to recognize anomalies or events that could become safety-related conditions. Some useful sections in Subparts I, L, and M include:

192.455	192.473	192.485	192.614	192.711	192.721
192.459	192.475	192.487	192.615	192.713	192.723
192.465	192.477	192.489	192.705	192.715	192.739
192.467	192.481	192.613	192.706	192.717	

4.3 Analysis and follow-up of in-line inspection (ILI).

Special consideration should be given to the development of written procedures for the timely analysis of, and follow through on, information obtained through the use of an ILI tool.

(a) An anomaly discovered with an ILI tool may be determined to be a safety-related condition when adequate information is available. For instance, adequate information would be available for each anomaly that is physically examined. Absent physical examination of each indicated anomaly, adequate information may be obtained when the ILI data is validated. For guidance on validation, see Guide Material Appendix G-192-14.

(b) The date an anomaly is discovered by an operator's representative and the date the anomaly is determined by an operator's representative to be a safety-related condition are used to determine the filing deadline stated in the reporting requirements of §191.25.

(c) See §192.933 and Guide Material Appendix G-192-14.

4.4 Actions in response to potential safety-related conditions.

(a) Procedures should be established for personnel to determine if a potential safety-related condition meets the reporting criteria in §191.23 and to file a report in accordance with §191.25. See Guide Material Appendix G-191-3 for a chart useful in determining if reports must be filed.

(b) When general corrosion is discovered that has reduced the pipe wall thickness to less than that required for the MAOP, actions should be taken to restore the pipe integrity (e.g., replace the pipe, reduce the MAOP).

(c) When localized corrosion pitting is discovered that has progressed to a degree where leakage might result, actions should be taken to prevent leakage at that location, such as installing a repair clamp.

(d) When unintended movement or abnormal loading by environmental causes is discovered that impairs the serviceability of a pipeline segment, actions should be taken to monitor the pipeline segment until the integrity and serviceability can be restored.

(e) When an observed condition involving a material defect or physical damage is determined to impair the serviceability of a pipeline segment, actions should be taken to monitor the pipeline segment until the integrity and serviceability can be restored.

(f) When there are indications that the pressure of a pipeline has risen above its MAOP plus the buildup allowed for the operation of pressure limiting or control devices, consider the following actions which may vary depending upon the situation.

(1) Initial actions.

(i) Verify that an overpressure condition has occurred by performing one or more of the following.

(A) Dispatch personnel for field investigation.

(B) Review SCADA information.

(C) Review pressure records.

(ii) Isolate the malfunctioning equipment or other cause of the overpressurization, if practicable, and reduce the pressure in the pipeline to normal operating pressures.

(iii) Determine whether the magnitude of overpressure warrants taking the pipeline out of service immediately.

(iv) Determine the extent of possible impact (e.g., a single customer, multiple customers

(A) SCADA and pressure recorders can be used to identify overpressured segments requiring possible corrective action.

(B) For low-pressure distribution systems, determine whether gas utilization equipment has been adversely affected. Notify affected customers if damage is suspected. Consider notifying emergency responders and public officials.

(v) Repair or replace the malfunctioning equipment that caused the overpressurization.

(2) Additional actions.

(i) Perform an instrumented leak survey of the overpressured pipe.

(A) Consider taking the pipeline out of service based on the nature of discovered leaks.

(B) Consider examining and repairing non-hazardous leaks on overpressured piping.

(ii) Determine the duration of the overpressurization.

(iii) Address transmission lines as follows.

(A) Comply with the notification requirements of §191.25(b).

(B) Determine the highest percentage of SMYS attributed to the overpressure event.

(C) For segments subject to integrity management under §192.917(e), determine whether the overpressured pipe needs to be prioritized as a high risk segment for the baseline assessment or a subsequent reassessment.

(D) For additional information about transmission lines, see 3 above.

(iv) Determine the cause of the overpressurization to reduce the likelihood of a recurrence. See guide material under §192.617.

(v) Assess the need for replacement of system components exposed to pressures greater than manufacturers' test pressures.

(vi) In the event of an operating error, see the operator's Drug and Alcohol Testing and Operator Qualification Programs, if appropriate.

(vii) Retain documentation of the event and of the corrective actions taken to continue the safe operation of the pipeline. For recordkeeping on transmission lines, see §192.709.

(g) Leaks that may constitute an emergency are responded to in accordance with the procedures required by §§192.615 and 192.703. See leakage control guidelines for Grade 1 leaks in Guide Material Appendices G-192-11 and G-192-11A.

(h) Anomalies or events that could lead to an imminent hazard and cause a 20% or more reduction in operating pressures or shutdown of operation of the effected pipeline segment should be responded to in accordance with the procedures required by §§192.615 and 192.703.

5 SURVEILLANCE, EMERGENCY RESPONSE, AND ACCIDENT INVESTIGATION

See guide material under §§192.613, 192.615, and 192.617.

6 TRAINING

6.1 Operations and maintenance (O&M) procedures.

Each operator should establish a training program that will provide operating and maintenance personnel with a basic understanding of each element of the procedural manual for operations, maintenance, and emergencies appropriate to the job assignment. A significant change in operating conditions, such as flow reversal or conversion to gas service, might warrant additional training. See 2.7 above regarding periodic reviews, procedure modifications, and retraining of personnel.

6.2 Operations and maintenance tasks.

See Subpart N.

6.3 Emergency response procedures.

Each operator is required by §192.615(b)(2) to train the appropriate operating personnel to ensure that they are knowledgeable of the emergency procedures. See 2 of the guide material under §192.615.

7 OTHER CONSIDERATIONS

7.1 "Work authorization" programs.

Operators should consider including written procedures in their procedural manual for operations, maintenance, and emergencies to protect maintenance workers from the unexpected movement or release of energy when working on electrical, pressurized fluid, or mechanical systems where the inadvertent actuation or release of energy could be dangerous. The procedures commonly used to protect maintenance personnel include "lockout," "tagout," "blocking," and "work authorization" programs. Equipment that should be considered includes compressors, filters, scrubbers, launchers, heat exchangers, and powered valve actuators.

7.2 Operator's use of powered equipment.

Before using powered equipment for making an excavation, the operator should consider the following.

(a) The use of pertinent maps, other records, or other means to locate the operator's facilities.

(b) Verifying that all other operators of underground facilities in the area have been notified of the pending excavation and have responded by marking their facilities.

(c) Determining safe distances to be maintained between the digging end of the powered equipment and underground facilities.

(d) The use of qualified personnel as necessary. See OPS Advisory Bulletin ADB-06-01 (71 FR 2613, Jan. 17, 2006; reference Guide Material Appendix G-192-1, Section 2).

7.3 Verification of established MAOP

(a) Operators should consider including written procedures in their manual for operations, maintenance, and emergencies that address the actions to be taken after records or materials are discovered that may call into question a pipeline's established MAOP. These written procedures should address the following, as applicable.

(1) Date the pipeline segment became regulated as outlined in §192.13, and how to address unknown or newly discovered records, or record discrepancies.
(2) Review of maintenance and construction activities subsequent to the original pressure test to verify that any repairs, relocations, or replacements meet the MAOP requirements and have the proper test and material documentation.
(3) Discovery of a pressure test record used to establish the pipeline's current MAOP that has a lower test value, a shorter test duration, or other test record that does not meet the requirements for a valid pressure test as outlined in Subpart J.
(4) Review of §§192.619, 192.621, 192.623 and 192.611 to determine if MAOP calculations are still valid.
(5) Options to use field verification for a record indicating an unknown strength or rating, or a pressure rating less than the pipeline's established MAOP.
(6) Consideration of an appropriate operating pressure reduction or restriction.
(7) Coordination with operator's gas control personnel for planning potential operating pressure changes that could affect control room operations.

(b) If the MAOP verification indicates changes to MAOP are necessary, the operator should consider the following actions.
(1) Assessing the impact to the pipeline system.
(2) Identifying a remediation strategy for addressing deficiencies.
(3) Revising the operator's pipeline records, which may include:
   (i) manual for operations, maintenance, and emergencies.
   (ii) gas control records.
   (iii) gas control alarms.
   (iv) GIS.
   (v) electronic databases.
   (vi) other records and documents where the operator may record pipeline MAOP data.
(4) Communicating the change to the appropriate operator personnel.
(5) Reviewing and revising overpressure protection requirements.
(6) Identifying potential reporting requirements.

(c) If an operator suspects that liquid hydrocarbons might be present in PE pipe, either from the surrounding soil or from liquid in the gas stream, they should perform a heat fusion melt pattern test on the pipe. If the operator sees bubbles in the PE pipe melt pattern or the fusion bead has a rough, pockmarked surface appearance, this might be an indication that liquid hydrocarbons have permeated the outer pipe wall. The operator should follow their procedures for repair of pipe with an incomplete heat fusion melt pattern. If the operator suspects that liquid hydrocarbons have penetrated the PE pipe wall, see the guide material under §192.121 regarding the effect of liquid hydrocarbons on design pressure. The operator might need to reduce the MAOP established under §192.619 based on the presence of liquid hydrocarbons.

(d) Operators who have determined that liquid hydrocarbons are present in PE pipes should determine the source of liquid hydrocarbons or gas condensates. If a source can be identified and eliminated, the operator should take appropriate steps to eliminate the liquid hydrocarbons. It is possible for the hydrocarbons to migrate out of the pipe wall over time if the source of contamination is eliminated. If subsequent melt pattern tests no longer have bubbles, the liquid hydrocarbons are no longer present in the PE pipe and the pipe's design pressure no longer requires adjustment due to the liquid hydrocarbons.

§192.607

Verification of Pipeline Material Properties and Attributes: Onshore steel transmission pipelines.

[Effective Date: 07/01/2020]

(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 in 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 multiples 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 the 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 excavations 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 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 re not consistent with available information or existing expectations or assume 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 assume yield strength of 24,000 pisi in accordance with § 192.107(b)(2).

[Amdt. 192-125, Oct. 1, 2019]

GUIDE MATERIAL

1 APPLICABILITY

(a) Section 192.607 only applies to onshore steel transmission pipelines. This section does not apply to offshore transmission, non-steel transmission, gathering, or distribution pipelines.

(b) Section 192.607 defines a process that an onshore steel gas transmission pipeline operator must follow if there are missing material property or attribute records that are required by other sections of Part 192. Examples include the following.

(1) Section 192.624 requires verification of material properties for certain types of pipelines that do not have traceable, verifiable, and complete MAOP records.

(2) Section 192.712 requires verification of certain material properties under §192.607 for onshore steel gas transmission pipelines that do not have records necessary to determine the predicted failure pressure (PFP) of a segment for specific anomalies or defects.

(3) Even if not explicitly required under Part 192, operators may elect to follow §192.607 to determine material attributes when material records are unknown or unreliable.

2 DOCUMENTATION OF MATERIAL PROPERTIES AND ATTRIBUTES

Records for material properties must be maintained for the life of the pipeline and should be traceable, verifiable, and complete (TVC). Operators should consider digitizing the records to enhance proper organization, security, and controlled access.

3 VERIFICATION OF MATERIAL PROPERTIES AND ATTRIBUTES

(a) There is no compliance deadline for completing material verification of non-TVC segments or components. The opportunistic gathering of data on unknown material properties does not need to meet the MAOP reconfirmation schedule outlined in §192.624(b), except when the selected MAOP reconfirmation method requires material properties testing to reconfirm the MAOP. The timeframe for opportunistic data collection may vary based on the length of the pipeline, amount of pipe with missing material properties, number of opportunities, and testing results. Section 192.712 requires the operator to know the pipe material properties when conducting the analysis of predicted failure pressure for anomalies or defect evaluations.

(b) If material properties are unknown and are necessary for an MAOP reconfirmation (per §192.624), an engineering critical assessment (per §192.632), or a failure pressure analysis (per §192.712), then operators should verify the unknown material properties needed on an opportunistic basis.

(c) Operator procedures should establish specific criteria for identifying when opportunistic sampling is appropriate. Operators should consider when pipeline exposures are safe for material verification and identify criteria that would render an exposure inappropriate for material verification, such as confined space concerns or unstable excavations.

(d) Section 192.607(c) states that certain types of excavations could require a material verification opportunity for non-TVC segments. Pipeline segment exposures during excavation activities covered under §192.614 are not included in these types of excavations. However, if material verification is performed for non-TVC segments during a one-call excavation, it must be performed per §192.607.

(e) Depending on the in-line inspection tool capabilities, operators can use pipe grade, wall thickness, and seam type derived from in-line inspection tools for material verification under §192.607(c). Verification of material properties and attributes using nondestructive methods or in-line inspection tools must meet the requirements in §192.607(d).

4 SPECIAL REQUIREMENTS FOR NON-DESTRUCTIVE METHODS

(a) Operators should consider using in-line inspection tool capabilities that can verify pipe grade, wall thickness, and seam type within the required confidence levels. If using in-line inspection to verify attributes, the operator should ensure its procedures meet the requirements of §192.607(d).

(b) Depending on the equipment being used for nondestructive testing, operators should consider requiring the equipment used for nondestructive testing to be calibrated on site, in order to prevent the equipment from losing calibration during transit. The documentation associated with the calibration for nondestructive testing, in accordance with §192.607, should be stored for the life of the pipe with the records used to document the physical pipeline characteristics and attributes.

5 SAMPLING MULTIPLE SEGMENTS OF PIPE

(a) Operators should only split populations based on known attributes of the pipe and they should have separate populations of pipe segments where material property attributes are unknown. Operators that can document pipe material properties for MAOP (e.g., outside diameter, wall thickness, yield strength, seam type), but are missing the manufacturing or construction date attributes, would not need to conduct an expanded sampling program to determine additional material properties.

(b) When required material documentation is missing, operators should implement a material sampling program for each unique pipe population group with unknown pipe attributes. Operators can initially group pipe segments with no known material properties information into a single population. When performing material properties testing on pipe from the unknown population group, operators should add newly verified samples into matching pipe populations or create new pipe population groups, as applicable.

(c) Use of certain in-line inspection tools that can collect material properties would be appropriate to delineate various pipe population groups for subsequent material sampling.

(d) Operators may take advantage of pipeline excavations and exposures to collect material properties regardless of pipeline location. If operators plan to use material and attribute information collected from pipe segments outside of HCA, MCA, and Class 3 and 4 areas to fulfill the requirements of §§ 192.624 and 192.712, they should adopt and follow procedures for implementing §192.607(e) in those areas as well.

6 COMPONENTS

Some component pressure ratings can be obtained from field inspection if there are visible manufacturing stamps or tags that identify the pressure rating of the fitting. For most flanges, taking measurements of the flange thickness and bolt pattern could help identify the vintage and pressure rating by comparison to early editions of ASME/ANSI B16.1 or ASME/ANSI B16.5.

7 UPRATING

If a segment's MAOP is established using the assumed yield strength of 24,000 psi and material verification of SMYS confirms a higher yield strength or material specification value in accordance with §192.607(d), those verified values may be used to uprate the MAOP of that segment in accordance with Subpart K.

8 ADDITIONAL GUIDANCE

On September 15, 2020, PHMSA issued a final list of Frequently Asked Questions (FAQs) related to the Final Rule titled *"Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments."* This includes FAQs associated with §192.607 *"Verification of Pipeline Material Properties and Attributes: Onshore steel transmission pipelines."* These FAQs can be found within federal docket number PHMSA-2019-0225.

§192.609

Change in class location: Required study.

[Effective Date: 11/12/70]

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.

GUIDE MATERIAL

(a) When an analysis of population density indicates an increase in class location, studies are required for transmission lines and Type A gathering lines operating at a hoop stress above 40 percent of SMYS (§192.609). When a class location change occurs, the pipeline MAOP might be affected.

(b) Pipeline maximum allowable operating pressures (MAOPs) are limited by class location design factors as defined in §192.111(a), by class location test pressure safety factors as defined in §192.619(a)(2), or by alternative MAOP class location design and test factors as outlined in §192.620(a)(1) and (2). Class 4 locations have the highest safety factors. The design factor allowed for Class 4 locations yields a design pressure with a hoop stress no greater than 40 percent of SMYS. Therefore, pipelines operating at or under 40 percent do not require a confirmation of MAOP under §192.611, and no study is required.

(c) Changes in class location might require a modification of the MAOP as required by §192.611. Pipelines with an established MAOP at or below 40 percent of SMYS do not require confirmation or changes in MAOP because the operating hoop stress of these pipelines is already commensurate with any of the class location hoop stress levels.

(d) Transmission lines and Type A gathering lines with an established MAOP at or below 40 percent of

SMYS, or Type B gathering lines, do not require studies.

(e) In cases where the reduction in class location (e.g., Class 2 to Class 1, Class 3 to Class 2) could allow operation of the pipeline at a higher operating hoop stress, the MAOP cannot be increased unless the pipeline is uprated in accordance with Subpart K.

(f) Changes in class location might change inspection frequencies, such as those found in §§ 192.705 and 192.706.

§192.610

Change in class location: Change in valve spacing.

[Effective Date: 10/05/2022]

(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, 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 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 1 contiguous mile during any 24-month period.

[Amdt. 192-130, 87 FR 20940, Apr. 8, 2022]

§192.611

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

[Effective Date: 12/22/08]

(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 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 2 locations, 0.667 times the test pressure for Class 3 locations, and 0.555 times the test pressure for Class 4 locations.

(ii) The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

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

(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.

[Amdt. 192-5, 36 FR 18194, Sept. 10, 1971; Amdt. 192-53, 51 FR 34987, Oct. 1, 1986; Amdt. 192-63, 54 FR 24173, June 6, 1989 with Amdt. 192-63 Correction, 54 FR 25716, June 19, 1989; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-94, 69 FR 32886, June 14, 2004; RIN 2137-AE25, 73 FR 62148, Oct. 17, 2008; Eff. date stayed by 73 FR 72737, Dec. 1, 2008]

GUIDE MATERIAL

This section applies to transmission lines and Type A gathering lines operating above 40 percent SMYS.

SPECIAL PERMIT (WAIVER) FOR CLASS LOCATION

Note: A "special permit" was previously referred to as a "waiver" by PHMSA-OPS. State terminology may differ (e.g., waiver, variance).

(a) When the MAOP of a pipeline is not commensurate with the new class location, PHMSA-OPS will consider special permit (waiver) requests under §190.341 to implement alternative measures to provide an equivalent or greater level of safety, provided that the terms and conditions of the special permit are met.

(b) Operators of interstate pipelines are required to submit special permit (waiver) requests to PHMSA-OPS. Operators of intrastate pipelines are required to submit requests to the state pipeline regulatory authority or to PHMSA-OPS if there is no state pipeline regulatory authority.

§192.612

Underwater inspection and reburial of pipelines in the Gulf of Mexico and its inlets.

[Effective Date: 09/09/04]

(a) Each operator shall prepare and follow a procedure to identify its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water that are at risk of being an exposed underwater pipeline or a hazard to navigation. The procedures must be in effect August 10, 2005.

(b) Each operator shall conduct appropriate periodic underwater inspections of its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water based on the identified risk.

(c) If an operator discovers that its pipeline is an exposed underwater pipeline or poses a hazard to navigation, the operator shall—

(1) Promptly, but not later than 24 hours after discovery, notify the National Response Center, telephone: 1-800-424-8802, of the location and, if available, the geographic coordinates of that pipeline.

(2) Promptly, but not later than 7 days after discovery, mark the location of the pipeline in accordance with 33 CFR part 64 at the ends of the pipeline segment and at intervals of not over 500 yards (457 meters) long, except that a pipeline segment less than 200 yards (183 meters) long need only be marked at the center; and

(3) Within 6 months after discovery, or not later than November 1 of the following year if the 6 month period is later than November 1 of the year of discovery, bury the pipeline so that the top of the pipe is 36 inches (914 millimeters) below the underwater natural bottom (as determined by recognized and generally accepted practices) for normal excavation or 18 inches (457 millimeters) for rock excavation.

(i) An operator may employ engineered alternatives to burial that meet or exceed the level of protection provided by burial.

(ii) If an operator cannot obtain required state or Federal permits in time to comply with this section, it must notify OPS; specify whether the required permit is State or Federal; and, justify the delay.

[Issued by Amdt. 192-67, 56 FR 63764, Dec. 5, 1991; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-98, 69 FR 48400, Aug. 10, 2004]

GUIDE MATERIAL

1 IDENTIFICATION

1.1 Criteria for identifying pipelines.

Operators are required to identify their pipelines located in the Gulf of Mexico and its inlets, where the water is less than 15 feet deep as measured from mean low water. Rivers, tidal marshes, lakes, and canals are excluded. Operators may determine where the water depth of the Gulf of Mexico and its inlets is 15 feet or less by referencing USGS maps or depth charts, USCG water depth maps or tables, or their own construction and maintenance records.

1.2 Assessing risk of identified pipelines.

Operators should assess the risk of such pipelines being exposed or being a hazard to navigation by considering the following.

(a) Types of vessels navigating the water body.
(b) Traffic density of vessels navigating the water body.
(c) Possible effects that hurricanes or other significant natural occurrences might have on pipeline depth of cover.
(d) History of pipeline damage from navigating vessels.
(e) Geological restrictions to navigation over the pipeline, such as the proximity of a land mass or the presence of water much shallower than 15 feet.
(f) Results of previous underwater inspections of the pipeline.
(g) Changing conditions of the sea floor, such as scouring, shifting, mudslides, collapsing, and silting.

2 INSPECTION

2.1 Inspection frequencies and prioritization.

(a) Operators may use the information obtained in 1.2 above to establish the frequency for inspecting each pipeline.
(b) Operators should prioritize the order in which the pipelines may be inspected and inspect those of perceived higher risk first, and possibly more frequently.
(c) Pipelines that operators determine are at risk of becoming a hazard to navigation or becoming exposed should be inspected more often, but operators should establish intervals for repeating inspections based upon the risks.

2.2 Inspection methods.

Operators may employ any suitable method, or a combination of methods, for underwater pipeline inspection based upon conditions required by a pipeline's specific environment. Operators should consider the following methods.

(a) Divers.
(b) Ultrasound or sidescan sonar.
(c) Remotely operated underwater inspection devices or vehicles (e.g., ROVs).
(d) Photography.
(e) Probing.

3 REPORTING (§192.612(c)(1))

In addition to the reporting requirements of §192.612(c)(1), an operator should also consider including the following.

(a) Latitude and longitude of the pipeline end points.
(b) Offshore area name.
(c) Offshore block number.
(d) Name of water body.
(e) Name of parish or county.

(f) Other pertinent information.

4 REMEDIAL ACTION

If an operator is unable to meet the deadline for remediation, the required notification to OPS should be in writing.

§192.613
Continuing surveillance.

[Effective Date: 05/24/23]

(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 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.

[Amdt. 192-132, 87 FR 52224, Aug. 24, 2022]

GUIDE MATERIAL

This guide material is under review following Amendment 192-132.

Note: Although not required, operators should consider including Type B gathering lines in continuing surveillance efforts.

1 GENERAL

Continuing surveillance should be conducted to identify any pipeline facilities experiencing abnormal or unusual operating and maintenance conditions. This may be accomplished by periodic inspections and reviews as discussed in (a) and (b) below.

(a) Periodic visual inspection of pipeline facilities to identify items such as the following.
- (1) Changes in population densities.
- (2) Effects of changes in topography.
- (3) Effects of exposure or movement.
- (4) Effects of encroachments.
- (5) Specific circumstances relating to patrolling and leakage. See guide material under §§192.705, 192.706, 192.721, and 192.723.
- (6) Potential for, or evidence of:
  - (i) Excavation activity. *Note:* If evidence of an excavation is found near a transmission pipeline covered segment, the location must be examined in accordance with §192.935(b)(1)(iv).
  - (ii) Tampering, vandalism, damage, or suspicious activities possibly leading to acts of sabotage. See guide material under §191.5 regarding reporting of such occurrences. *Note:* As appropriate, an operator should report such instances to local law enforcement.
  - (iii) Earth movement. See Guide Material Appendix G-192-13.
  - (iv) Flooding. See 6 below.
  - (v) Mining activity. See Guide Material Appendix G-192-13.
  - (vi) Soil or water accumulation in vaults or pits.
  - (vii) Gas migration through air intakes into buildings from vaults and pits.
  - (viii) Excessive snow and ice build-up on aboveground facilities (e.g., meter sets, pressure control equipment, heaters) that could affect their function.

(b) Periodic review and analysis of records, such as the following.
- (1) Patrols
- (2) Leak surveys.
- (3) Valve inspections.
- (4) Vault inspections.
- (5) Pressure regulating, relieving, and limiting equipment inspections.
- (6) Corrosion control inspections.
- (7) Facility failure investigations.
- (8) Reported vandalism, sabotage, or suspicious activities. Tools and resources to help operators plan, prepare, and protect themselves from suspicious activities or attacks are located online at www.cisa.gov/connect-plan-train-report.
- (9) As-built and facility location maps.

(c) Anomalies discovered should be evaluated, and those determined to present potential safety concerns should be scheduled for remediation and communicated to appropriate integrity management personnel.

(d) If a discrepancy is noted between what is observed in the field and the record, the discrepancy should be resolved as soon as practicable. Examples might include:
- (1) The service line record shows a plastic service line, but in the field it is observed to be a steel line of a different diameter. Ensure records are updated and accurate.

(2) The service line record for two adjacent homes is shown as a branch service, but when the service tee was retired, one of the homes still remained active with gas pressure. Confirm the source of gas feeding the home and update records to accurately show the facility location.

2 CAST IRON PIPELINES

For cast iron pipelines, see Guide Material Appendix G-192-18.

3 PE PIPELINES

3.1 Brittle-like cracking.

(a) Some PE materials manufactured before 1982 have a lower resistance to the effects of induced stresses and are subject to brittle-like cracking under certain in-service conditions (e.g., rock impingement, squeeze-offs, severe bending moments). Brittle-like cracking is characterized by a part-through crack initiating in the pipe wall followed by slow crack growth causing failure. These failures result in a tight slit-like opening and a gas leak. This older generation of PE may have leak-free performance for a number of years before brittle-like cracks occur. An increase in the occurrence of leaks is typically the first indication of a brittle-like cracking problem.

(b) PE materials that are most known for this failure mode include the following.
  (1) Century Utility Products, Inc. products.
  (2) Low-ductile inner wall PE 2306 "Aldyl A" pipe manufactured by DuPont Company during 1970 through 1972, generally NPS 1¼ to NPS 4. To determine if the "Aldyl A" pipe has low-ductile inner wall, see 3(f) below.
  (3) PE gas pipe designated PE 3306.
  (4) DuPont PE tapping tees with DuPont Delrin® polyacetal (homopolymer) inserts (see 3(g) below).
  (5) Plexco PE service tees with Celanese Celcon® polyacetal (copolymer) caps (see 3(h) below).

(c) Conditions that may cause these types of materials to fail prematurely include the following.
  (1) Inadequate support and backfill during installation.
  (2) Tree root or rock impingement.
  (3) Shear and bending stresses due to differential settlement resulting from factors such as:
    (i) Excavation in close proximity to PE piping.
    (ii) Directional drilling in close proximity to PE piping.
    (iii) Frost heave.
  (4) Bending stresses due to pipe installations with bends exceeding recommended practices.
  (5) Stresses where the pipe has been squeezed off.

(d) Each operator that has these older PE pipelines should consider the following practices.
  (1) Review system records to determine if any known susceptible materials have been installed in the system.
  (2) Perform more frequent inspection and leak surveys on systems that have exhibited brittle-like cracking failures of known susceptible materials.
  (3) Collect failure samples of PE piping exhibiting brittle-like cracking.
  (4) Record the print line from any piping that has been involved in a failure. The print line information can be used to identify the resin, manufacturer, and year of manufacture for plastic piping.
  (5) For systems where there is no record of the piping material, consider recording print line data when piping is excavated for other reasons. Recording the print line data can aid in establishing the type and extent of PE piping used in the system.
  (6) Develop procedures for taking appropriate action, including pipe replacement, to mitigate potential pipe failures.
  (7) Use a consistent record format to collect data on system failures. It is recommended that operators use a standard industry form developed for gathering data on plastic pipe failures to help trend and evaluate the extent of plastic pipe performance problems. For information about such form, visit the AGA website at www.aga.org under "Operations and Engineering/Plastic Piping Data Project."

(e) For those pipeline systems that contain products manufactured by Century Utility Products, Inc.

between 1970 and 1973, the systems should be monitored and necessary replacements made for system integrity and public safety.

(f) An operator can determine if the PE 2306 "Aldyl A" piping manufactured by DuPont Company during 1970 through 1972 has low-ductile inner wall by using the following procedure.
  (1) Cut a ½-inch ring from the pipe.
  (2) Cut the ring at one point.
  (3) Reverse bend the ring, exposing the inner surface of the pipe.
  (4) Bend back the ring until the outer surfaces of the pipe (or cut ends) touch.
  (5) Cracking on the inner surface of the ring in the bend area indicates low-ductile inner wall.

(g) DuPont PE tapping tees with Delrin polyacetal inserts were installed in gas systems from the late 1960s to the early 1980s and should be replaced or remediated according to manufacturer's recommendations as they are discovered. These can be distinguished by a black cap with male threads and a tan PE body.

(h) Plexco PE service tees with Celcon polyacetal caps were installed in gas systems prior to 1996. Caps that show marks from the use of a tool (e.g., pipe wrench or Channellock®-type pliers) on the cap should be replaced.

(i) References concerning brittle-like cracking in PE materials include the following.
  (1) NTSB Reports
    (i) PAB-98-02 available at www.ntsb.gov/investigations/AccidentReports/Reports/PAB9802.pdf
    (ii) SIR-98-01 available at www.ntsb.gov/safety/safety-studies/Documents/SIR9801.pdf
  (2) OPS Advisory Bulletins (see Guide Material Appendix G-192-1, Section 2) as follows.
    (i) ADB-99-01 (64 FR 12211, Mar. 11, 1999).
    (ii) ADB-99-02 (64 FR 12212, Mar. 11, 1999).
    (iii) ADB-02-07 (67 FR 70806, Nov. 26, 2002 with Correction, 67 FR 72027, Dec. 3, 2002).
    (iv) ADB-07-02 (72 FR 51301, Sept. 6, 2007 with Correction, 73 FR 11192, Feb. 29, 2008).
  (3) "Correlating Aldyl 'A' and Century PE Pipe Rate Process Method Projections with Actual Field Performance," E.F. Palermo, Ph.D., Plastics Pipes XII Conference, April 2004, available at https://www.aga.org/wp-content/uploads/2022/12/gptctechpaper.pdf.

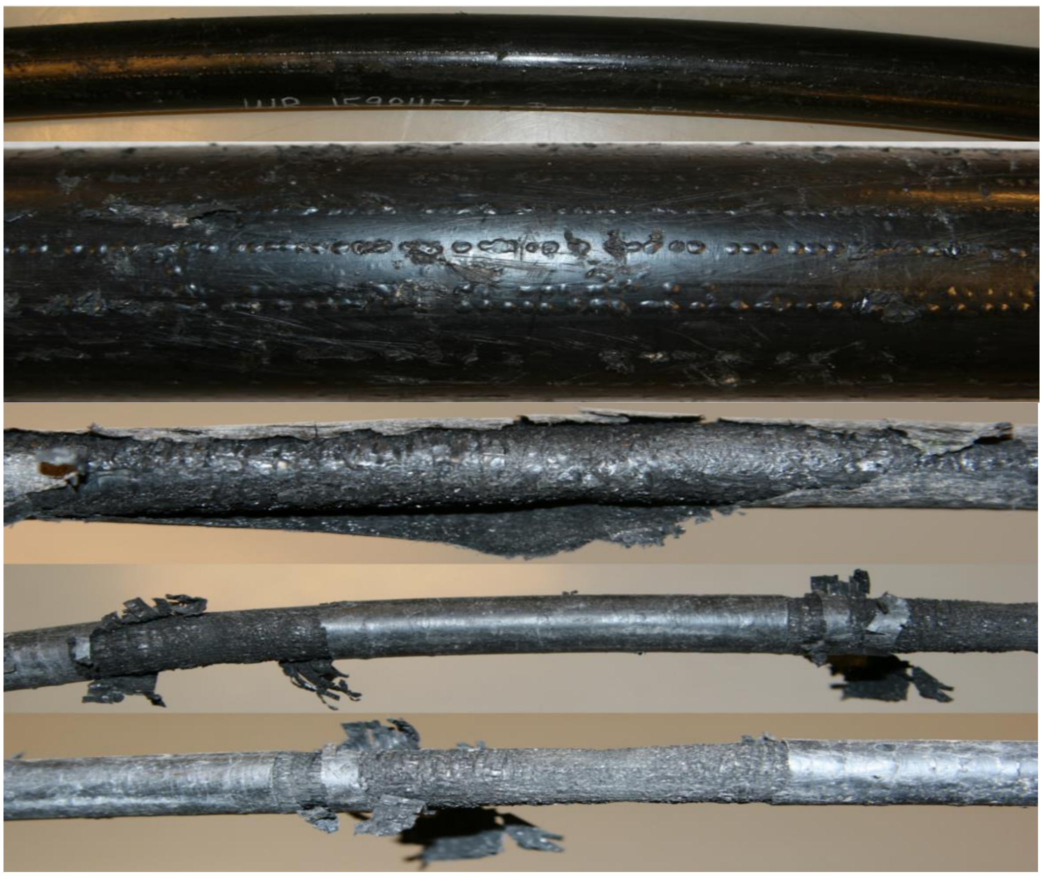
3.2 Degradation due to thermal oxidation.

Driscopipe® 7000 and 8000 high-density (HD) PE pipe exposed to prolonged elevated temperatures might degrade as a result of thermal oxidation. The mechanism for this oxidation appears to be the depletion of the thermal stabilizer, which has been shown to occur over time in regions of high ambient temperatures. There is no evidence that other PE piping products are similarly affected. Driscopipe® 7000 and 8000 HDPE pipes were produced from pipe materials that contained specific and unique additives.

(a) Based on laboratory testing and observed field performance, the regions of the U.S. that have the highest ambient temperature conditions are of particular concern.

(b) The potential for thermal oxidation of Dricopipe® 7000 and 8000 HDPE pipe increases as a function of elevated pipe temperature and exposure time. Segments of pipe that are not actively flowing gas such as service lines; CTS services (typically service lines) have experienced more leakage than IPS sizes (typically mains).

(c) Thermal oxidation might present as external degradation on the outside surface of the pipe or internal degradation on the inside surface of the pipe, or both.
  (1) External degradation might be observed through visual inspection of the pipe or detected audibly by squeezing of the pipe (see 3.2(f) below). External degradation does not normally result in a loss of integrity or leakage, provided the material is still sound below the degraded surface.
  (2) External degradation might pose operational concerns for the operator as joining of the pipe might require special fittings to avoid creating a source of leakage with externally sealing fittings. Operators are encouraged to consider externally degraded pipe segments for replacement. Another consideration is decreasing the maximum operating pressure of the pipe to account for wall loss attributed to external degradation.



Note: **Photographs of pipes provided with permission of the operator.**

INDUSTRY-RECOGNIZED MITIGATION METHODS	
Mitigation Method	**Description**
	repairs, can be used to reduce the likelihood of a stress corrosion failure. Examples include eddy current and electromagnetic acoustic transducer (EMAT) tools.
Engineering Critical Assessment	A written document that evaluates the risks of SCC and provides a technically defensible plan to demonstrate satisfactory pipeline safety performance. The document considers the defect growth mechanisms of the SCC process.

TABLE 192.613ii

5 THREADED JOINTS

Operators that have threaded joints in underground gas systems may want to determine if increased surveillance is warranted. Factors that could be considered include wall thickness, leak history, susceptibility to corrosion, settlement, frost-induced movement, and third-party damage.

6 SEVERE FLOODING AND GROUND MOVEMENT

Severe flooding and ground movement can adversely affect the safe operation of a pipeline. Operators should consider the following actions in areas prone to, or previously affected by, flooding and ground movement.

(a) Identify pipeline facilities that are in the flood plain, such as overlaying 100-year flood elevations on GIS pipeline maps.

(b) For buried pipelines, consider the following.

(1) Engaging hydrologists, geomorphologists, or other experts in river flow to evaluate the potential for scour or channel migration that might affect the identified pipeline facilities.

(2) Evaluating terrain and vegetation conditions that can cause severe scouring of the watercourse. Such conditions could include burned areas subject to sediment erosion and long-term buildup of debris and vegetation.

(3) Evaluating river or water crossings to determine if the pipeline installation method is sufficient to withstand the risks posed by areas prone to flooding, scour, or channel migration.

(4) Determining the maximum flow or flooding conditions at river or water crossings where pipeline integrity is at risk due to flooding or scouring and having contingency plans to shut down and isolate those pipelines when such conditions occur. Where appropriate, provide copies of the contingency plan and review with the pipeline controllers.

(5) Installing drainage measures in the trench to mitigate subsurface flows and enhance surface water draining at the site.

(6) Installing trench breakers and slope breakers to mitigate trench seepage and divert trench flows along ground surface to a safe discharge point off the site or right-of-way.

(7) Evaluating geological and environmental conditions, changing weather patterns and soil stability near facilities and consider using available data and information resources to assess vulnerabilities related to landslides and earth movement (i.e., cascading hazards). Cascading hazards are chains of adverse events like floods leading to slope failures or denuded slopes, causing slope failures during the next storm, which cause more extreme flooding.

(8) Looking for indications of ground movement (e.g., tension cracks along the surfaces of slopes, scarping, leaning posts or poles, curving tree trunks (gravitropism)). Tension cracks and scarps indicate possible failure is underway (downslope movement such as slips or landslides), while leaning posts or poles and curving tree trunks are indicators of slope creep. Both processes are types of slope failures.

(9) Examining infrastructure at ground level for cracks or indications that the infrastructure has shifted position. Ground movement can be caused by subsidence processes. For example, cracks in foundations are a good indication that ground level may be sinking over time.

(10) Monitoring for ground movement, if suspected. Equipment such as strain gauges, inclinometers, piezometers, or geodetic monitoring points could be considered to monitor

movement.

(11) For information regarding preventative and mitigative measures, see guide material under §§ 192.935 or 192.1007(d).

(c) For aerial or aboveground pipeline crossings, consider the potential for the following.
  (1) Scouring of deadman anchors and tower foundations on cable-supported pipelines and traffic or pedestrian bridges.
  (2) Floating debris impacting the pipeline and its supports beneath or on the upstream side of traffic or pedestrian bridges.

(d) Extend regulator vents and relief stacks above the level of anticipated flooding, as appropriate.

(e) Determine if facilities that are normally above ground (e.g., valves, regulators, relief devices) could become submerged and then have a potential for being struck by vessels or debris, and consider protecting or relocating such facilities.

(f) For additional information regarding severe flooding and geological hazards, see the following OPS Advisory Bulletins (see Guide Material Appendix G-192-1, Section 2)
  (1) ADB-2019-01 (84 FR 14715, April 11, 2019).
  (2) ADB-2019-02 (84 FR 18919, May 2, 2019).
  (3) ADB-2022-01 (87 FR 33576, June 2, 2022).

7 SERVICE LINES UNDER BUILDINGS

Buried and uncased service lines discovered under buildings should be moved to locations no longer beneath the building or reinstalled under the building in accordance with the requirements of §192.361. In instances involving mobile homes, it may be possible to have the home relocated away from the service line. See guide material under §192.361.

8 INTEGRITY MANAGEMENT CONSIDERATIONS

Conditions or information discovered that could affect the integrity of a pipeline should be reported to the appropriate integrity management and operating personnel. Examples include the following.

(a) Evidence of one or more of the following
  (1) External corrosion.
  (2) Deteriorated coating.
  (3) Cathodic protection current shielding.
  (4) Failed insulators.

(b) Corrosion discovered through an ILI run or other integrity assessment that requires remedial action in accordance with §§192.485 or 192.933.

(c) Evidence of internal corrosion or conditions conducive to internal corrosion including observed liquids or significant changes in gas quality.

(d) Excavation damage or conditions conducive to excavation damage to the pipeline.

(e) Damage or conditions conducive to damage to the pipeline by natural or other force.

(f) Evidence of potential material failure of pipe or weld.

(g) A leak.

(h) Any abnormal operation (e.g., loss of communications, overpressure or pressure fluctuations, pipeline security concerns). See §192.605(c)

(i) Recent construction or demolition activity of nearby structures.

(j) Change in number of structures intended for human occupancy that could affect class location or HCA determination.

§192.614

Damage prevention program.

[Effective Date: 07/20/98]

(a) Except as provided in paragraphs (d) and (e) of this section, each operator of a buried pipeline shall 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 excavation, blasting, boring, tunneling, backfilling, the removal of aboveground structures by either explosive or mechanical means, and other earthmoving operations.

(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 §198.37 of this chapter; or

(2) The one-call system:

(i) Is operated in accordance with §198.39 of this chapter;

(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) A damage prevention program under this section is not required for the following pipelines:

(1) Pipelines located offshore.

(2) Pipelines, other than those located offshore, in Class 1 or 2 locations until September 20, 1995.

(3) Pipelines to which access is physically controlled by the operator.

(e) 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.

[Issued by Amdt. 192-40, 47 FR 13818, Apr. 1, 1982; Amdt. 192-57, 52 FR 32798, Aug. 31, 1987; Amdt. 192-73, 60 FR 14646, Mar. 20, 1995; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-82, 62 FR 61695, Nov. 19, 1997; Amdt. 192-84, 63 FR 7721, Feb. 17, 1998 with Amdt. 192-84 Removal, 63 FR 38757, July 20, 1998 and Amdt. 192-84 Correction, 63 FR 38758, July 20, 1998]

GUIDE MATERIAL

Note: Section 192.616 requires most operators, including Type A and Type B gathering line operators, to develop and implement a written continuing public education program that follows the guidance provided in API RP 1162 for identifying and notifying excavators and the affected public about damage prevention. These identification and notification activities are required by §192.614. Guide material for these program activities is provided in 2.3, 2.4, and 2.5 below.

1 SCOPE

This guide material covers damage prevention programs for buried pipelines, including Type A and Type B gathering lines. The guide material excludes pipelines specified under §192.614(d) and (e) that are exempt from the requirement for a written damage prevention program. For considerations to minimize damage by outside forces, see Guide Material Appendix G-192-13.

Some activities performed as requirements for damage prevention may also be used to satisfy similar program requirements under §§192.615, 192.616, 192.620(d)(2), and 192.935.

2 WRITTEN PROGRAM

Written procedures, when required, should state the purpose and objectives of the damage prevention program and provide methods to achieve them. For program content, operators should review applicable state and local one-call requirements. A reference for state requirements is the One Call Systems International (OCSI) Resource Guide, which provides a summary of the damage prevention laws in each state, found at https://commongroundalliance.com/map. In addition, operators should review the Common Ground Alliance's "Best Practices" Guide, found at https://commongroundalliance.com/best-practices-guide. The procedures should include the following.

2.1 Definition of excavation activities.

In defining excavation activities to be covered by the damage prevention program, the operator should review the definition in §192.614(a) and applicable state and local requirements. Additional definitions for "excavation" and "excavator" can be found in 49 CFR §196.3.

2.2 One-call systems.

(a) A one-call system may exist that does not meet the qualification requirements of §192.614(b)(1) or (b)(2). If the operator participates in a non-qualified one-call system, either because a qualified one-call system does not cover the area or for any other reason, the operator should consider working with that one-call system to make it qualified.

(b) If a one-call system covering the operator's facilities does not exist, the operator should consider establishing a qualified one-call system with other underground facility operators.

(c) The operator is cautioned that satisfying the requirements of §192.614 may require more than participation in a one-call system. The operator should evaluate the services being provided by the one-call system to determine what additional measures may need to be taken to satisfy the requirements of §192.614.

(2) Circumstances under which gas might be allowed to safely escape to the atmosphere (i.e., vent) until shutdown or repair.
   (i) Some possible reasons for using this alternative are as follows.
      (A) Curtailment will affect critical customers (e.g., hospitals).
      (B) Curtailment will affect large numbers of customers during adverse weather conditions.
      (C) Line break or leak is remotely located and does not cause a hazard to the public or property.
   (ii) Some factors to consider are as follows.
      (A) Sources of ignition.
      (B) Leak or damage location (rural vs. urban).
      (C) Proximity to buildings and other structures.
      (D) Local emergency responders' ability to access the search and rescue area.
      (E) Ability to make and keep the area safe while gas vents.
      (F) Ability to coordinate with operator and local emergency responders and public officials.
(3) Lists or maps of valve locations, regulator locations, compressor schematics, and blowdown locations.
(4) Maps or other records to identify sections of the system that will be affected by the operation of each valve or other permanent shutdown device.
(5) Provision for positive identification of critical valves and other permanent facilities required for shutdown. See 2.2 of the guide material under §192.605.
(6) Instructions for operating station blowdown and isolation systems for each compressor station. See Guide Material Appendix G-192-12.
(7) Provisions for notifying affected customers.
(8) Provisions for confirming that the shutdown or pressure reduction was effective.

(b) Distribution system plans should include consideration of the potential hazards associated with an outage and the need to minimize the extent of an outage, and to expedite service restoration. In addition to the use of any existing emergency valves within a distribution system, consideration should also be given to other methods of stopping gas flow, such as:
   (1) Injecting viscous materials or polyurethane foam through drip risers or any other available connections to the main.
   (2) Use of squeeze-off or bagging-off techniques.

1.7 *Making safe any actual or potential hazard*.
Provisions should be described for identifying, locating, and making safe any actual or potential hazard. These may include the following.
(a) Controlling pedestrian and vehicular traffic in the area.
(b) Eliminating potential sources of ignition.
(c) Controlling the flow of leaking gas and its migration. See Guide Material Appendices G-192-11 for natural gas systems and G-192-11A for petroleum gas systems.
(d) Ventilating affected premises.
(e) Venting the area of the leak by removing manhole covers, barholing, installing vent holes, or other means.
(f) Determining the full extent of the hazardous area, including the discovery of gas migration and secondary damage such as the following.
   (1) Deformation of a gas service line indicating that the service line might be separated underground near a foundation wall or at an inside meter set assembly.
   (2) Multiple underground leaks that may have occurred, allowing gas to migrate into adjacent buildings.
   (3) Potential pipe separation and gas release at unseen underground locations that may result in gas entering adjacent buildings, or following or entering other underground structures connected to buildings.
(g) Monitoring for a change in the extent of the hazardous area.
(h) Determining whether there are utilities whose proximity to the pipeline may affect the response.

(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.

[Issued by Amdt. 192-71, 59 FR 6579, Feb. 11, 1994; Amdt. 192-99, 70 FR 28833, May 19, 2005 with Amdt. 192-99 Correction, 70 FR 35041, June 16, 2005; Amdt. 192-103, 71 FR 33402, June 9, 2006; RIN 2137-AE17, 72 FR 70808, Dec. 13, 2007]

GUIDE MATERIAL

1 GENERAL

The public education program should be tailored to the type of pipeline operation (transmission, distribution, gathering) and the environment traversed by the pipeline. Section 192.616(b) requires the operator to assess the unique attributes and characteristics of the operator's facilities. Operators in the same area should attempt to coordinate their program activities to properly direct reports of emergencies and to avoid inconsistencies.

Some activities performed as requirements for public awareness may also be used to satisfy similar program requirements under §§192.614, 192.615, 192.620(d)(2), and 192.935.

Operators of petroleum gas distribution systems or smaller gas systems (e.g., master meter operators) subject to §192.616 should review the "Guidance Manual for Operators of LP Gas Systems" or the "Guidance Manual for Operators of Small Natural Gas Systems" available at and strict policies on peripheral devices (e.g., removable media, printers, scanners) connected to the SCADA network.

(6) Monitoring unauthorized usage.

(b) See references in 10 below.

5 OPERATING EXPERIENCE

(a) An operator should periodically review relevant operating information to enhance the control room management plan. Reportable incidents (for definition, see §191.3) must be reviewed to determine if the following factors contributed to the incident (§192.631(g)(1)).

(1) Controller fatigue.
(2) Field equipment.
(3) Control room procedures.
(4) SCADA configuration and performance.
(5) Operation of any relief device (for transmission facilities, the operation of a relief device should already be noted as an abnormal operation).

(b) Post-emergency reviews, as required by §192.615(b)(3), should examine whether controller actions contributed to the emergency. In addition to emergencies and reportable incidents, an operator should review abnormal operations (§192.605(c)), accidents, failure investigations (§192.617), root-cause investigations, or near misses as these might also provide valuable information. Any deficiencies or improvements noted during the review should be documented, and changes to the procedures should be implemented, if appropriate.

(c) The review procedure should specify the records needed to provide documentation of the incident reviews.

6 MANAGEMENT OF CHANGE (§192.631(f))

(a) Changes are regular occurrences during the course of pipeline operations requiring effective management through established processes and procedures. Operators should identify and document changes that might impact a controller's ability to monitor or control the pipeline facilities. Communications between the control room, management, and field personnel are a vital part of the control room MOC process. Operators should consider controller involvement when implementing the following changes to pipeline facilities.

(1) Temporary interruption or limitation of gas flow (e.g., valve closure, pipeline shutdown).
(2) Restoration of gas flow capability (e.g., valve opening, completion of maintenance outage).
(3) Temporary limitation or restoration of control (e.g., compressor maintenance outage, regulator or city-gate station maintenance).
(4) Temporary or permanent change in pipeline flow patterns (e.g., placing new pipeline facility in service, removing a pipeline from service, flow reversal).
(5) Change in established MAOP due to regulatory oversight or integrity management limitation.
(6) Purchase or sale of assets.
(7) Change to existing equipment (e.g., valves, piping) or new equipment coming online.
(8) Newly constructed facility (e.g., pipeline, compressor station, measurement or regulator station) being turned on line.
(9) Converting an existing liquid pipeline to gas service
(10) Procedural change affecting operations, maintenance, or safety.
(11) Change to operating agreement.
(12) Pigging or other maintenance activity.
(13) Change to control systems or SCADA.
(14) Emergency or abnormal situation.
(15) Implementation of change resulting from the required reviews in 5 above.

(b) Information about planned changes (e.g., temporary flow patterns, new facilities, blow- down activities) to a controlled pipeline facility should be brought to the attention of the controller through direct planning involvement.

Leakage surveys of Type B gathering lines require the use of leakage detection equipment (§192.9(d)(8)).

§192.707

Line markers for mains and transmission lines.

[Effective Date: 07/13/98]

(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.

(b) *Exceptions for buried pipelines*. Line markers are not required for the following pipelines:

(1) Mains and transmission lines located offshore, or 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 until March 20, 1996.

(4) Transmission lines in Class 3 or 4 locations where placement of a line marker is impractical.

(c) *Pipelines aboveground*. Line markers must be placed and maintained along each section of a main and transmission line that is located aboveground 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 (or name of gas transported) Pipeline" all of which, except for markers in heavily developed urban areas, must be in letters at least 1 inch (25 millimeters) high with 1/4 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.

[Amdt. 192-20, 40 FR 13502, Mar. 27, 1975 with Amdt. 192-20A, 41 FR 56807, Dec. 30, 1976; Amdt. 192-27, 41 FR 34598, Aug. 16, 1976 with Amdt. 192-27 Correction, 41 FR 39752, Sept. 16, 1976; Amdt. 192-40, 47 FR 13818, Apr. 1, 1982; Amdt. 192-44, 48 FR 25206, June 6, 1983; Amdt. 192-73, 60 FR 14646, Mar. 20, 1995; Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL

(a) If an existing pipeline has undergone a conversion to service (see §192.14) or other change of product transported, the line markers should accurately list the product.
(b) See Guide Material Appendix G-192-13, Section 3.

§192.709

Transmission lines: Record keeping.

[Effective Date: 07/08/96]

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 a least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.

[Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996]

GUIDE MATERIAL

(1) See Guide Material Appendix G-192-17 for the explicit requirements of each patrol, survey, inspection, or test required by Subparts L and M.

(2) See guide material under §192.947 for records required under Subparts I, L, and M to be used as part of the operator's Integrity Management Program for transmission lines.

(3) See guide material under §192.227 for records demonstrating the qualification of each individual welder at the time of construction of steel transmission and regulated gathering lines.

(4) See §192.285(e) for records demonstrating the qualification of each individual plastic pipe joiner at the time of construction of plastic transmission line.

§192.710

Transmission lines: Assessments outside of high consequence areas.

[Effective Date: 05/24/23]

(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.

[Amdt. 192-125, Oct. 01, 2019, Amdt. 192-132, 87 FR 52224, Aug. 24, 2022]

GUIDE MATERIAL

This guide material is under review following Amendment 192-125 sequence, the effect of wall thickness and heat input, and the quenching effect of the gas flow.

(b) Welding should be done only on sound metal far enough from the defect so that the localized heating will not have an adverse effect on the defect. The soundness of the metal may be determined by visual and other nondestructive inspection.

(c) A reference is API Std 1104, "Welding of Pipelines and Related Facilities", Appendix B, "In-Service Welding" (see listing in §192.7, not IBR for §192.713).

3.2 Additional precautions.

(a) Care should be taken in excavating around the pipe so that it is not damaged.

(b) Pounding on the pipe (e.g., to remove corrosion products or pipe coating, or to improve the fit of the sleeve) should be avoided.

3.3 Reliable engineering tests and analyses.

See guide material under §192.485.

4 PIPE REPLACEMENT (§192.713(a)(1))

Pipe replacement by cutting out and replacing a cylinder of pipe is a repair option under §192.713 and should be considered for repair of dents, wrinkles, or other pipe changes such as expanded pipe or buckles. Replacement can use pipe that has been pre-tested to the appropriate pressure for the MAOP.

5 SPLIT SLEEVE REPAIR (§192.713(a)(2))

5.1 General.

(a) The use of an appropriately designed full-encirclement split sleeve is recognized as an acceptable repair method. Other methods are also available, such as the use of composite-reinforced wrap material addressed in 7 below. The operator is advised to follow manufacturer’s instructions for installation.

(b) The operator should determine the type of sleeve to be used in the repair.

(1) Type A sleeve provides defect reinforcement. This type of split sleeve restores the strength of the pipe by containing and reinforcing the defect and reduces bulging of a defective area. The two parts of the split sleeve are installed around the pipe to provide the required reinforcement. Effectiveness of the repair is improved by using a filler material (e.g., polyester epoxy) in the defect which provides support. Type A sleeves are assembled by bolting or welding (welding to the carrier pipe might not be necessary). This type of sleeve cannot be used to repair leaks and should not be used for circumferential defects or deep defects since corrosion could occur in the annular space between the carrier pipe and sleeve.

Note: Composite wrap repairs are a type of reinforcing sleeve (see 7 below).

(2) Type B sleeve is a pressure containing sleeve. A pressure containing split sleeve provides a different function and can be used to contain a leak or to reinforce an area where a defect exists. Because the sleeve contains pressure, operators are advised to select a sleeve commensurate with the current carrier pipe MAOP. The application of the Type B sleeve requires the sleeve ends to be fillet welded to the pipe. The use of low hydrogen welding procedures, additional support of the pipe because of the additional weight, and welding inspection of the fillet welds should be considered before using this type of repair.

Note: Some Type B sleeves might also be called by other names (e.g., pumpkins, watermelons, turtles) due to the shape of the sleeves being suitable to fit around couplings.

(c) In determining the length of the repair, the operator should consider that:

(1) Some degree of impairment might have occurred beyond the area of immediate concern (see 1.3 above), and

(2) Full-encirclement sleeves should not be less than 4 inches in length.

(d) A wide variety of repair methods have been used successfully in the gas pipeline industry. Sleeves may be used to reduce the stress in, or reinforce, a pipe defect that is not leaking, or to repair a leaking defect. It is important that any repair method or sleeve be designed and tested to ensure its reliability for the conditions of installation.

actively being used to transport gas and the permanent abandonment of transmission lines, Type A gathering lines, distribution mains, and distribution service lines. See 5 below for information regarding inactive pipelines.

(b) For planned shutdown in connection with abandonment or deactivation, see Guide Material Appendix G-192-12.

(c) Abandonment should not be considered complete until the gas or liquid hydrocarbons contained within the abandoned section poses no potential hazard. An operator should consider diameter, length, location, or other parameters when identifying piping to be abandoned that needs to be purged.

(d) Pipelines may be purged using air, inert gas, or water. If air is used as the purging agent, precautions should be taken to ensure that no liquid hydrocarbons are present. See §192.629 and AGA XK1801, "Purging Manual" for purging of gas and liquid hydrocarbons.

2 ABANDONMENT OF TRANSMISSION PIPELINES AND DISTRIBUTION MAINS

2.1 Check prior to abandonment.

Office records should be checked and necessary field checks should be made to ensure the pipelines or mains scheduled for abandonment are disconnected from all sources and supplies of gas, such as other pipelines, mains, crossover piping, meter stations, customer piping, control lines, and other appurtenances.

2.2 Sealing.

Acceptable methods of sealing pipeline or main openings include, as applicable, the following.

(a) Using normal end closures, such as welded or screwed caps, screwed plugs, blind flanges, and mechanical joint caps and plugs.
(b) Welding steel plate to pipe ends.
(c) Filling ends with a suitable plug material.
(d) Pinching the ends closed.

2.3 Additional considerations in addition to purging and sealing.

In addition to purging and sealing, consideration should be given to the following.

(a) Filling the abandoned segment with water or an inert gas to prevent potential combustion hazard.
(b) Other action designed to prevent hazardous cave-ins resulting from pipe collapse caused by corrosion or external loading.

2.4 Segmenting the abandoned sections.

All valves left in the abandoned segment should be closed. If the segment is long and there are few line valves, consideration should be given to plugging the segment at intervals.

2.5 Removal of above-grade facilities and filling voids.

All above-grade valves, risers, and vault and valve box covers should be removed. Vault and valve box voids should be filled with suitable compacted backfill material.

3 ABANDONMENT OF DISTRIBUTION SERVICE LINES IN CONJUNCTION WITH MAIN ABANDONMENT

3.1 Curb valves and curb boxes.

All curb valves should be closed. The top section of curb boxes located in dirt areas should be removed and the void filled with suitable compacted backfill material. If boxes are set in concrete or asphalt, they should be filled with suitable compacted backfill material to an appropriate distance from the top of the box and the fill completed with suitable paving material.

3.2 Meter risers and headers.

Meter risers and headers should be dismantled and removed from the premises.

(i) Atmospheric corrosion.
(ii) Susceptibility to damage from vehicles and other forces.
(iii) Unauthorized activities.

6 INACTIVE SERVICE LINES

In addition to 5.2 above, the operator should consider the following for continuing maintenance of inactive service lines.
(a) Identifying and documenting the location of inactive service lines in a record management system.
(b) Developing criteria for abandonment.

§192.729
(Removed.)
[Effective Date: 02/11/95]

§192.731
Compressor stations: Inspection and testing of relief devices.
[Effective Date: 11/22/82]

(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.

[Amdt. 192-43, 47 FR 46850, Oct. 21, 1982]

GUIDE MATERIAL

The MAOP of regulated segments of gathering lines could be protected by equipment that is located in non-regulated compressor stations. While the compressor station might not be subject to Part 192 due to its location, individual devices that provide overpressure protection or isolation of downstream regulated segments could be regulated.

Although not required for non-regulated devices, operators of Type B gathering lines should consider performing routine inspections of overpressure protection devices.

§192.733
(Removed.)
[Effective Date: 02/11/95]

§192.735

Compressor stations: Storage of combustible materials.

[Effective Date: 08/06/15]

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

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

[Amdt. 192-119, 80 FR 168, Jan. 5, 2015 with Amdt. 192-119 Correction, 80 FR 46847, Aug. 6, 2015]

GUIDE MATERIAL

No guide material necessary.

§192.736

Compressor stations: Gas detection.

[Effective Date: 07/13/98]

(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.

[Issued by Amdt. 192-69, 58 FR 48460, Sept. 16, 1993; Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL

1 GENERAL

See §192.171 for design of gas detection and alarm systems.

2 MAINTENANCE AND TESTING OF GAS DETECTION AND ALARM SYSTEMS

The operator should develop the following.

(a) Maintenance and testing procedures to ensure proper function of the gas detectors and alarm system.
(b) Procedures for calibrating the gas detection equipment and verifying that the alarms are functioning properly.

§192.737
(Removed.)
[Effective Date: 02/11/95]

§192.739
Pressure limiting and regulating stations: Inspection and testing.
[Effective Date: 10/08/04]

(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 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) Except as provided in paragraph (b) of this section, set to control or relieve at the correct pressures consistent with the pressure limits of §192.201(a); and

(4) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

(b) For steel pipelines whose MAOP is determined under §192.619(c), if the MAOP is 60 psi (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.

[Amdt. 192-43, 47 FR 46850, Oct. 21, 1982; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003; Amdt. 192-96, 69 FR 27861, May 17, 2004 with Amdt. 192-96 DFR Confirmation, 69 FR 54248, Sept. 8, 2004]

GUIDE MATERIAL

1 GENERAL

1.1 Gathering lines.

(a) The MAOP of gathering lines could be protected by equipment that is located outside of the regulated segment of pipeline. While the pressure limiting station, relief device, or regulating station might not be subject to Part 192 due to its location, individual devices that provide overpressure protection or isolation of downstream regulated segments could be regulated by function.

(b) Although not required for non-regulated devices, operators of Type B gathering lines should consider performing routine inspections of overpressure protection devices.

1.2 General considerations.

(a) Prior to operating equipment, a review of the station's operating mode(s) should be performed using resources such as station schematics or SME input. The operator should follow system operation procedures including applicable recommendations for Control Room Management plans (see guide material under §192.631). The review should include the operating system pressure and what might occur during overpressurization event.
(b) Where necessary, consider marking or labeling the equipment requiring special attention such as regulator bypass valves, relief device isolation valves, and valves associated with control, sensing, and supply lines. See guide material under §192.203.
(c) When it is necessary to continue gas flow through a manually controlled bypass to inspect or test station components, the manual valve should be operated by personnel who are qualified (see Subpart N) to control the pressure in the downstream system at or below its MAOP. The pressures should be continuously monitored and the valve adjusted to prevent an overpressure condition. The manual bypass valve should be clearly marked showing the direction it is to be turned to either open or close the valve.
(d) Gas systems that experience an interruption in electric service due to rolling electric blackouts or unplanned electric system outages might be negatively affected by an abrupt turn-on or turn-off of the electricity. Operators might experience pressure drops, pressure loss in entire gas systems, or pressure relief devices releasing gas to atmosphere. Operators should consider monitoring critical pressure regulating stations during known blackout periods and conducting additional inspections after the electric system outages.

2 VISUAL INSPECTIONS

Visual inspections should be made to determine that a satisfactory condition exists which will allow proper operation of the equipment. The following should be included in the inspection, where necessary.

(a) Station piping supports, pits, and vaults for general condition and indications of ground settlement. Prior to entering a vault that has restricted openings (e.g., manholes) or which is more than four feet deep, and while working therein, tests should be made of the atmosphere in the vault. See guide material under §192.749 for atmospheric test procedures.
(b) Station doors and gates, and pit and vault covers to ensure that they are functioning properly and that access is adequate and free from obstructions.
(c) Ventilating equipment installed in station buildings or vaults for proper operation and for evidence of accumulation of water, ice, snow, or other obstructions.
(d) Control, sensing, and supply lines for conditions that could result in a failure.
(e) All locking devices for proper operation.
(f) Posted station schematics for correctness.

3 STOP VALVES

An inspection or test of stop valves should be made to ensure that the valves will operate and are correctly positioned. Caution should be used to avoid any undesirable effect on pressures during operational checks. The following should be included in the inspection or test.

(a) Station inlet, outlet and bypass valves.
(b) Relief device isolating valves.
(c) Control, sensing, and supply line valves.

4 PRESSURE REGULATORS

4.1 General operating conditions.

Consideration should be given to taking the station out of service during inspection and testing activities. Each pressure regulator used for pressure reduction or for pressure limiting should be inspected or tested. The procedure should ensure that each regulator is in good working order, controls at its set pressure, operates or strokes smoothly, and shuts off within the expected and accepted limits. If acceptable operation is not obtained during the operational check, the cause of the malfunction should be determined and the appropriate components should be adjusted, repaired, or replaced as required. After repair, the regulator should be checked for proper operation.

4.2 *Special conditions*.

(a) Regulator bodies that are subjected to erosive service conditions may require visual internal inspection.
(b) More frequent inspections or additional inspections may be required as a result of construction and hydrostatic testing upstream.
(c) More frequent inspections or additional inspections may be required as a result of abnormal changes in operating conditions or unusual flows or velocities.
(d) Whenever abnormal pressures are imposed on pressure or flow devices, the event should be investigated and a determination made as to the need for inspection and repairs.
(e) Inspection and testing should be performed during times of low station throughput or when the station can be taken out of service, if practical.

5 RELIEF DEVICES

(a) The inspection or test should ensure the following.
  (1) Correct set pressure of relief devices. See 5(b) below for testing for correct set pressure.
  (2) Correct liquid level of liquid seals.
  (3) That the stacks are free of obstructions.
(b) One of the methods listed below may be used to test for correct set pressure. Test connections should include a gauge or deadweight tester so arranged that the pressure at which the device becomes operative may be observed and recorded.
  (1) The pressure may be increased in the segment until the device is activated. During the tests, care should be exercised to ensure that the pressure in the segment protected by the relief device does not exceed the limit in §192.201.
  (2) The pressure from a secondary pressure source may be added to the pilot or control line until the device is activated.
  (3) The device may be transported to a shop for testing and returned to service. When the device is to be shop-tested or otherwise rendered inoperative, adequate overpressure protection of the affected segments should be maintained during the period of time the relief device is inoperative.
(c) See §192.743 for reviewing and calculating, or testing, the required capacity of relief devices.

6 FINAL INSPECTION

The final inspection procedure should include the following.

(a) A check by personnel who are qualified (see Subpart N) for proper position of all valves. Special attention should be given to regulator station bypass valves, relief device isolating valves, and valves in control, sensing, and supply lines.
(b) Restoration of all locking and security devices to proper position.

7 OVERPRESSURE PROTECTION CONSIDERATIONS FOR LOW-PRESSURE DISTRIBUTION SYSTEMS

During an activity that could potentially cause overpressurization, use the type of gauges suitable (pressure range) for the system being worked on. Continuously observe and monitor the operating pressures in appropriate locations. Leave gauges in place for an appropriate length of time after the work is completed to identify any lagging pressure changes.

§192.740

Pressure regulating, limiting and overpressure protection – Individual service lines directly connected to production, gathering, or transmission pipelines.

[Effective Date: 03/12/21]

(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 other 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.

[Amdt. 192-123, 82 FR 7998, Jan. 23, 2017]

GUIDE MATERIAL

No guide material available at present.

§192.741

Pressure limiting and regulating stations: Telemetering or recording gages.

[Effective Date: 11/12/70]

(a) Each distribution system supplied by more than one district pressure regulating station must be equipped with telemetering or recording pressure gages 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 telemetering or recording gages 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.

GUIDE MATERIAL

1 MAINTENANCE OF TELEMETERING INSTRUMENTS, RECORDING GAUGES, AND RECORDS

1.1 Operation, testing, and maintenance of instruments.
All instruments used for telemetering or recording pressures should be operated in accordance with the manufacturers' recommended instructions, and should be inspected and tested in accordance with said instructions at intervals not exceeding 1 year.

1.2 Review of recording charts.
Each operator should review the recorded pressure readings either at the time of inspection or shortly after the removal of the gauge chart from the gauge. Each operator should review the recorded pressure readings for the following.
(a) Any indication of abnormal operating condition (i.e., high- or low-pressure).
(b) Proper operation by the recording instrument.
(c) Proper operation of pressure regulating devices.

1.3 Identification of pressure charts.
The operator should indicate on each pressure recording chart the following information.
(a) Name of the operator.
(b) Location of recording gauge-station name or number or both.
(c) Date and time of recorded pressure readings.
(d) Any tests performed on the gauge during the recorded period.

1.4 Retention of pressure records.
All records showing the recorded pressure readings should be retained in accordance with requirements of the governmental agency that has jurisdiction over the operator, unless the operator requires their retention for a longer time period.

2 DISTRIBUTION SYSTEMS SUPPLIED BY MORE THAN ONE PRESSURE REGULATOR STATION (§192.741(a))

2.1 Telemetering or recording pressure gauge.
Each operator should install and maintain telemetering or recording pressure gauges at some points in the system. The location of the gauges is dependent upon the design of the system, and therefore, should be at points that would best indicate an abnormal operating condition.

2.2 Temporary recording gauges at low-pressure points.
Each operator should give consideration to installing temporary recording gauges at various locations in the distribution system at suspected or anticipated low-pressure points. The data compiled or derived from these gauges will assist the operator in determining the adequacy of the system design. These gauges should remain until the suspected condition is:
(a) Shown to be satisfactory; or
(b) Corrected.

2.3 Additional telemetering or recording pressure gauges.
If the system is such that installed gauges cannot adequately indicate the pressure in the distribution system, the operator should give consideration to installing additional telemetering or recording pressure gauges at selected points to assist in maintaining the maximum and minimum allowable operating pressures as required by §§192.619, 192.621, and 192.623.

3 DISTRIBUTION SYSTEMS SUPPLIED BY ONE PRESSURE REGULATOR STATION (§192.741(b))

3.1 Telemetering as early warning agent.
Telemetering of pressure or flow may be used as an early warning agent to disclose system failures or malfunctions. The following parameters should be considered to determine if a telemetering system is feasible and practical.
(a) Response time of operating personnel to the source of the telemetered signal.

(b) The magnitude of pressure drop or flow increase which would indicate a system failure.
(c) Design limits of the telemetering system to properly respond to the criteria established in (b) above.
(d) Recognition of possible failures to which the telemetry would not respond.
(e) Seasonal changes in normal pressure or flow requirements, which may require resetting the alarm limits.
(f) The complexity of the telemetry system to be installed. The system could vary from a simple high-low pressure switch alarm to a more sophisticated system transmitting signals to a computer.
(g) Location of the telemetered alarm at a center manned 24 hours a day having the capability to alert appropriate operating personnel.

On the basis of the foregoing factors, determine whether (1) the telemeter is feasible, and if so, (2) determine whether it is practical in relation to cost, probability of pipeline failure, proximity to the operating headquarters, risk analysis, and system safety.

3.2 Monitoring of single feed distribution system operations.
Even though the number of source points required to monitor a single feed distribution system may be fewer than the number required for a distribution system fed by more than one pressure regulator station, the guide material in 2.1, 2.2, and 2.3 above should be considered.

4 ABNORMAL OPERATING CONDITIONS (§192.741(c))

If an abnormal operating condition is indicated, the operator should:
(a) Investigate and determine if pressure regulating and auxiliary control equipment is in satisfactory operating condition. Any unsatisfactory condition found by inspection or test should be immediately corrected.
(b) Investigate and determine if the pressure recording device is in proper operating condition. Any unsatisfactory condition found by inspection or test should be corrected as soon as practical.
(c) Investigate the distribution system in the vicinity of a high-pressure or low-pressure condition.

§192.743

Pressure limiting and regulating stations: Capacity of relief devices.

[Effective Date: 10/08/04]

(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.

[Amdt. 192-43, 47 FR 46850, Oct. 21, 1982; Amdt. 192-55, 51 FR 41633, Nov. 18, 1986; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003; Amdt. 192-96, 69 FR 27861, May 17, 2004 with Amdt. 192-96 DFR Confirmation, 69 FR 54248, Sept. 8, 2004]

GUIDE MATERIAL

1 CAPACITY DETERMINATION BY IN-PLACE TESTING

1.1 Determination of actual flow.

The capacity of the relief valve system can be determined by direct measurement under full flow conditions or by determining a coefficient through limited flow tests that can be used in calculating the full capacity. References for performing the appropriate tests include the following.

(a) UG-131 of the ASME Boiler and Pressure Vessel Code, Section VIII (see listing in §192.7, not IBR for §192.743).

(b) API RP 525, "Testing Procedure for Pressure-Relieving Devices Discharging Against Variable Back Pressure" (Revised 1960; Discontinued).

1.2 Demonstrating adequate capacity.

(a) A test may be conducted by simulating conditions of maximum pressure and supply volume conditions for the pressure control source of the protected segment and minimum flow conditions on the discharge side of the source. Under these conditions the pressure control source should be wide open. Adequate capacity is determined if the relief device prevents the downstream pressure from exceeding that permitted by §192.201.

(b) When conducting such a test, care must be taken to maintain service and to prevent overpressuring any components in the system.

2 CAPACITY DETERMINATION BY CALCULATION

2.1 Determination of required relief capacity.

(a) The maximum possible flow through the source supplying the system being protected should be determined.

  (1) When the source is controlled by the operator, recognized engineering formulas may be used to make the calculations based on data published by, or otherwise obtained from, the manufacturer of the equipment used as a pressure source or pressure control component.

    (i) A lesser capacity than calculated above is acceptable if calculations of flow in the piping on the inlet or outlet of the equipment show a lesser throughput to be the maximum.

    (ii) Data used in these calculations should be selected so that the capacity calculated will represent the maximum throughput in actual operations, including emergencies. Minimum demand may be considered.

  (2) When the operator does not have control of the source, information should be obtained to adequately determine the maximum flow and pressure capacity of that source. This information may then be used as the basis for relief capacity requirements.

(b) When more than one pressure regulating or compressor station feeds a pipeline, relief capacity based on complete failure of the largest capacity regulator or compressor should be adequate. The operator should consider subsequent failures that may be caused by an initial failure.

2.2 Determination of relief device capacity.

See 2 of the guide material under §192.201.

3 REDETERMINATION

A redetermination of the required relief capacity should be made whenever there are changes in the system that could increase the supply of gas from the source, the capacity of the control device, or the ability of the relief device to handle the required flow.

4 GATHERING LINES

(a) The MAOP of gathering lines could be protected by equipment that is located outside of the regulated segment of pipeline. While the relief device might not be subject to Part 192 due to its location, individual devices that provide overpressure protection or isolation of downstream regulated segments could be regulated by function.

(b) Although not required for non-regulated devices, operators of Type B gathering lines should consider performing routine capacity calculations for relief devices.

§192.745

Valve maintenance: Transmission lines.

[Effective Date: 10/15/03]

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

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

(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), 192.179(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), 192.179(f), or 192.634 that is indicated to be inoperable or unable to maintain effective shut-off as follows:

(1) 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

(2) 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.

[Amdt. 192-43, 47 FR 46850, Oct. 21, 1982; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003; Amdt. 192-130, 87 FR 20940, Apr. 8, 2022]

GUIDE MATERIAL

This guide material is under review following Amendment 192-130.

1 INSPECTION AND MAINTENANCE

(a) Each operator should review the valve manufacturer's recommendations and develop an appropriate maintenance program.

(b) Valves should be operated to the extent necessary to establish operability during an emergency. When operating the valve, precautions should be taken to avoid a service outage or overpressuring the system.

(c) When maintenance is completed, the operator should verify that the valves are in the proper position.

(d) When inspecting or maintaining valves, the location reference data contained in the operator's records should be compared with field conditions. Changes, such as referenced landmarks, street alignment, and topography, should be noted and incorporated in the records.

(e) Gathering line emergency valves.

(i) While a valve protecting a Type A gathering line might not be subject to Part 192 due to its location, it could be regulated by function.

(ii) Although not required, operators should consider performing routine inspections on valves protecting Type B gathering lines.

2 PRECAUTIONS

If a valve is to be partially operated, precautions should be taken to avoid a service outage or overpressuring the system. Such precautions might include the following.

(a) Documenting the valve type (e.g., plug, gate, ball) and the direction and number of turns to operate the valve.

(b) Verifying the orientation of the valve in relation to the valve stops.

(c) Monitoring downstream pressure for any variation from normal operating pressure.

(d) Qualified personnel (see Subpart N) and system operating SME, if necessary, should be involved in the inspection or adjustment of any valve that could affect pressure regulating equipment or other pressure sensing equipment.

(e) See guide material under §192.739 for equipment associated with pressure regulation and overpressure protection.

3 INOPERABLE VALVES

The following actions should be considered if a valve is found inoperable.

(a) Repair the valve to make it operable.

(b) Designate another valve or valves to substitute for the inoperable valve that will provide a similar level of effectiveness for isolating the line section. Consideration should be given to the following.

(1) Spacing requirements as prescribed in §192.179.
(2) Updating records for emergency shutdown and future maintenance requirements.
(3) Informing employees of the change to the isolation or emergency shutdown plan.

(c) Replace the valve.

§192.747

Valve maintenance: Distribution systems.

[Effective Date: 10/15/03]

(a) Each valve, the use of which may be necessary for the safe operation of a distribution system, must be checked and serviced at intervals not exceeding 15 months, but at least once each calendar year.

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

[Amdt. 192-43, 47 FR 46850, Oct. 21, 1982; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003]

GUIDE MATERIAL

1 INSPECTION AND MAINTENANCE

Valves should be checked for adequate lubrication and proper alignment to permit the use of a key, wrench, handle, or other operating device. Where applicable, the valve box or vault should be cleared of any debris that would interfere with or delay the operation of the valve.

2 PRECAUTIONS

If a valve is to be partially operated, precautions should be taken to avoid a service outage or overpressuring the system. Such precautions might include the following.

(a) Documenting the valve type (e.g., plug, gate, ball) and the direction and number of turns to operate the valve.
(b) Verifying the orientation of the valve in relation to the valve stops.
(c) Monitoring downstream pressure for any variation from normal operating pressure.
(d) Qualified personnel (see Subpart N) and system operating SME, if necessary, should be involved in the inspection or adjustment of any valve that could affect pressure regulating equipment or other pressure sensing equipment.
(e) See guide material under §192.739 for equipment associated with pressure regulation and overpressure protection.

3 INOPERABLE VALVES

The following actions should be considered if a valve is found inoperable.

(a) Repair the valve to make it operable.
(b) Designate another valve or valves to substitute for the inoperable valve that will provide a similar level of effectiveness for isolating the desired area. Consideration should be given to the following.
    (1) Updating records for emergency shutdown and future maintenance requirements.
    (2) Informing employees of the change to the isolation or emergency shutdown plan.
(c) Replace the valve.

4 IDENTIFICATION AND RECORD VERIFICATION

(a) See §192.181 for additional information on identifying valves necessary for the safe operation of a distribution system.
(b) See guide material under §192.745 regarding verification of records with current field data.

§192.749

Vault maintenance.

[Effective Date: 07/13/98]

(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.

[Amdt. 192-43, 47 FR 46850, Oct. 21, 1982; Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL

1 APPLICABILITY

The following guide material applies to vaults that contain pressure regulating or pressure limiting equipment and have a volumetric internal content of 200 cubic feet or greater. Section 192.749 does not apply to valve access vaults, other underground vault-type structures that have a volumetric internal content of less than 200 cubic feet, or underground vault-type structures that do not contain pressure regulating or limiting equipment (e.g., emergency isolation valve, hand-hole access type). See guide material §192.3 for a definition of vault.

2 HAZARDOUS ATMOSPHERES

Hazardous atmospheres might exist in such vaults due to leakage from components within the vault, or from seepage of gases (e.g., natural gas, nitrogen) or other vapors, fumes, or mists (e.g., gasoline) from outside the vault.

3 DEVELOPMENT OF SAFETY PROCEDURES

Procedures for appropriate safety measures should be developed and should include the following.

3.1 Procedures prior to entry.

(a) Engine exhausts should be kept away from the vault opening.
(b) All possible sources of ignition should be kept away from the work area, except as may be required in the performance of the work. See §192.751.
(c) Sufficient safety equipment (e.g., dry chemical fire extinguishers, breathing apparatus, safety harnesses) should be available in the work area.
(d) Flashlights, lighting fixtures, and extension cords should be of a type approved for hazardous atmospheres.
(e) Before the cover is removed, the vault atmosphere should be tested for combustible gas. Use the holes or pry holes, or lift the edge of the cover slightly to admit the testing probe. In double cover manholes, it will be necessary to remove the outer cover and partially lift the inner cover to make the test.
(f) Immediately after removal of the cover, tests for combustible gas and for oxygen deficiency should be made at various levels that can be reached from the surface.
(g) Results of the tests made in accordance with 3.1(e) and (f) above should determine the procedures

to be followed.

(1) *Combustibles at 60% of the Lower Explosive Limit or Less (e.g., 3.0% natural gas in air or less)*. The vault may be entered without breathing apparatus after establishing, by test, that a safe oxygen level exists, or if continuous forced draft ventilation is maintained. Forced draft ventilation is superior to suction draft ventilation.

(2) *Combustibles in excess of 60% of the Lower Explosive Limit*. The vault should not be entered unless ventilation maintains combustible level below 60% of the Lower Explosive Limit and a safe oxygen level exists. However, in the event the vault cannot be adequately ventilated and the facility cannot be taken out of service to effect necessary repairs, the vault may be entered with the use of an approved breathing apparatus and safety harness.

3.2 Procedures for vault entry and while working in the vault.

(a) Ladders should be used when entering or leaving vaults.

(b) Upon entering a vault, workers should inspect or test the interior for abnormal or hazardous conditions.

(c) When workers enter vaults, at least one person should remain on the surface and, under ordinary circumstances, not leave the work location. In the event workers require a breathing apparatus and safety harness in accordance with 3.1(g)(2) above, at least two persons should remain on the surface (one being in a position to continuously observe activity in the vault).

(d) When workers enter vaults, the atmosphere should be retested for combustible gases and oxygen deficiency at intervals not to exceed one hour, or instrumentation providing continuous monitoring should be used.

(e) Only approved flashlights or lighting equipment should be used. Electrical connections and disconnections should be made outside the vault. See guide material under §192.751.

3.3 Procedures for vaults with restricted openings.

Safety measures should be considered for vaults that have restricted openings and are greater than 4 feet deep. OSHA regulations could be a source of safety information.

4 INSPECTION AND REPAIRS

(a) If gas is detected prior to entry or while working in the vault, or if the operator can hear or smell gas, the operator should follow the appropriate guide material in 3 above.

(b) In accordance with the operator's applicable O&M and safety procedures, the operator should enter or remain in the vault:

(1) To further investigate, classify, and repair the leak as necessary

(2) To inspect equipment in the vault including the ventilating equipment and ensure it is adequately operating as intended.

(c) Whenever personnel enter a vault, periodic or continuous monitoring should be performed in vaults where the oxygen levels could be depleted (see 3 above).

5 VAULT COVER INSPECTION (§192.749(d))

Consider the following during the vault cover inspection.

(a) Vault cover lacks a locking device or other tamper-proof measures to prevent unauthorized access.

(b) Vault cover is damaged or deteriorated to the point it is unsafe to open.

(c) Vault cover is damaged or deteriorated to the point it is unsafe to support expected external loads.

(d) Vault cover is not identified as housing gas facilities, as might be required by the operator or local regulatory authority.

(e) Any other hazardous condition that might be detrimental to public safety as deemed by the operator.

§192.750

Launcher and receiver safety.

[Effective Date: 07/01/2020]

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.

[Amdt. 192-125, Oct. 01, 2019]

GUIDE MATERIAL

This guide material is under review following Amendment 192-125.

§192.751

Prevention of accidental ignition.

[Effective Date: 11/12/70]

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.

GUIDE MATERIAL

1 GENERAL

1.1 Smoking and open flames.

Smoking and open flames should be prohibited in the following locations.

(a) In structures or areas containing gas facilities where possible leakage or presence of gas constitutes a hazard of fire or explosion.

(b) In the open when accidental ignition of gas-air mixture might cause personal injury or property damage.

1.2 Accidental electric arcing.

To prevent accidental ignition by electric arcing, the following should be considered.

(a) Flashlights, portable floodlights, extension cords, and any other electrically powered tool or equipment should be of a type approved for use in hazardous atmospheres. Care should be taken to ensure that electrical connections and disconnections are not made, and are prevented from occurring, in hazardous atmospheres.

(b) Internal combustion engines that power trucks, cars, compressors, pumps, generators, and other equipment should not be operated in suspected or known hazardous atmospheres.

(c) Bonding to provide electrical continuity should be considered around cuts separating metallic pipes that may have gas present. This bond should be installed prior to cutting and maintained until reconnections are completed or a gas free environment exists. Bond cables should be installed in a manner to ensure they do not become detached during construction and they provide minimal electrical resistance between pipe sections.

1.3 *Static electricity on plastic pipe.*

A static electric charge can build up on both the inside and outside of plastic pipe due to the dielectric properties of plastic. Discharging of the static electricity going to ground can cause an arc that will cause ignition if a flammable gas-air mixture is present. In plastic pipe operations, it is essential to avoid the accumulation of a flammable gas-air mixture and the arcing of a static electrical discharge. When conditions exist such that a flammable gas-air mixture may be encountered and static charges may be present, such as when repairing a leak, squeezing-off an open pipe, purging, making a connection, etc., arc preventing safety precautions are necessary. The following should be considered.

(a) Leaking or escaping gas should be eliminated by closing valves or excavating and squeezing-off in a separate excavation at a safe distance from the escaping gas.
(b) If escaping gas cannot be effectively controlled or eliminated and it is necessary to work in an area of escaping gas, safety provisions should be considered such as dissipating or preventing the accumulation of a static electrical charge, venting the gas from the trench, and grounding those tools used in the area. Additionally, flame-resistant clothing treated to prevent static buildup and respiratory equipment should be used. Acceptable methods of dissipating or preventing the accumulation of static electricity include wetting the exposed area with an electrically conductive liquid (e.g., soapy water with glycol added when ambient temperatures are below freezing) and using a anti-static polyethylene (PE) film or wet non-synthetic cloth wound around or laid in contact with the entire section of exposed pipe and grounded with a brass pin driven into the ground. Commercially available electrostatic discharge systems may be considered as a means of eliminating static electricity from both the inside and outside of PE pipe.
(c) A plastic pipe vent or blowdown stack should not be used due to the possibility that venting gas with a high scale or dust content could generate an internal static electrical charge that could ignite the escaping gas. Metal vent stacks should be grounded before placement in the escaping gas stream. Venting should be done downwind at a safe distance from personnel and flammable material.
(d) To reduce potential sources of ignition, all tools, including squeeze-off tools, used in gaseous atmospheres should be grounded or the non-sparking type.

1.4 *Other sources of ignition*.

Care should be taken in selecting the proper hand tools for use in hazardous atmospheres and in handling tools to reduce the potential for a spark.

1.5 *Fire extinguishers.*

If escaping gas in the area of the work is possible, a fire extinguisher should be available upwind and adjacent to the area.

1.6 *Verification of the presence of gas.*

Prior to welding, cutting, or performing other work on isolated sections of gas piping, a check should be made with a gas detector for the presence of a combustible gas mixture inside the pipe. Work should begin only when safe conditions are indicated. If the work takes place over an extended period of time, the line should be periodically monitored to ensure that a combustible gas mixture does not accumulate.

1.7 *Accidental ignition of discharged gas.*

Operators should consider using the following measures to help avoid accidental ignition when gas is discharged in areas subject to public motor vehicle or pedestrian traffic.

(a) Posting warning signs.
(b) Directing motor vehicles and pedestrians away from the area by considering the following.
    (1) Law enforcement.
    (2) Traffic flaggers.

(3) Signs (e.g., detour, road closed).
(4) Barricades.

2 WELDING, CUTTING, AND OTHER HOT WORK

2.1 General.
Prior to welding, cutting, or other hot work in or around a structure or area containing gas facilities, a thorough check should be made with a gas detector for the presence of a combustible gas mixture. Prior to entering pipe, tanks, or similar confined spaces, appropriate instruments should be used to ensure a safe, breathable atmosphere. Work should begin only when safe conditions are indicated. The atmosphere should be tested periodically for oxygen deficiency and combustible gas mixtures.

2.2 Pipelines filled with gas.
When a pipeline or main is to be kept full of gas during welding or cutting operations, the following are recommended.
(a) A slight flow of gas should be kept moving toward the cutting or welding operation.
(b) The gas pressure at the site of the work should be controlled by suitable means.
(c) All slots or open ends should be closed with tape, tightly fitted canvas, or other suitable material immediately after a cut is made.
(d) Two openings should not be uncovered at the same time.

2.3 Pipelines containing air.
(a) Before the work is started, and at intervals as the work progresses, the atmosphere in the vicinity of the zone to be heated should be tested with a combustible gas indicator or by other suitable means.
(b) Unless a suitable means (e.g., an air blower) is used to prevent a combustible mixture in the work area, welding, cutting or other operations that could be a source of ignition should not be performed on a pipeline, main, or auxiliary apparatus that contains air and is connected to a source of gas.
(c) When the means noted in 2.3(b) above are not used, one or more of the following precautions are suggested, depending upon the job site circumstances.
(1) The pipe or other equipment upon which the welding or cutting is to be done should be purged with an inert gas.
(2) The pipe or other equipment upon which the welding or cutting is to be done should be continuously purged with air in such a manner that a combustible mixture does not form in the facility at the work area.

3 ISOLATING PIPELINE SEGMENTS ON PLANNED WORK TO MINIMIZE THE POTENTIAL OF IGNITION

3.1 General.
Planned work on gas facilities should incorporate procedures to shut off or minimize the escape of gas. No portion of a pipeline, large-diameter service line, or main should be cut out under pressure, unless the flow of gas is shut off or minimized by the use of line valves, line plugging equipment, bags, stoppers, or pipe squeezers. Where 100% shutoff is not feasible, the following precautions are recommended.
(a) Plan the job to minimize the escape of gas and sequence steps to limit the time and amount of gas to which personnel are exposed.
(b) Ensure that the size and position of the cut allows the gas to vent properly even with an employee in the excavation.
(c) Protect personnel working in a gaseous atmosphere under an overhang, in a tunnel, or in a manhole.

3.2 Isolating pipeline segments.
(a) Preliminary action. The operator should conduct a prework meeting(s) to review the following with the personnel involved.
(1) The method of isolation.

(2) The purpose of each activity.
(3) Drawings, procedures, and schematics, as applicable.
(4) Responsibilities of each individual, including the designation of an individual to be in charge of the operation.

(b) Isolation precautions.
(1) The operator should ensure that the isolation equipment is appropriate and sized correctly for the job.
(2) Isolation equipment left unattended should have a positive means of preventing unauthorized operation.
(3) Positive means should be provided at the work site to alert and protect personnel from unintentional pressuring. Consideration should be given to the use or installation of items such as:
(i) Relief valves.
(ii) Rupture discs.
(iii) Pressure gauges.
(iv) Pressure recorders.
(v) Vents.
(vi) Pressure alerting devices.
(vii) Other pressure detecting devices.
(4) Isolation equipment should be inspected and maintained prior to use.
(5) Temporary closures capable of withstanding full line pressure should have a means to determine pressure buildup, such as gauges and vents.
(6) Consideration should be given to the following to prevent the uncontrolled release of liquid hydrocarbons when cutting into offshore pipelines or other pipelines that might contain significant quantities of these liquids.
(i) The elevation difference between the blowdown valve and cut location.
(ii) The impact of water displacement on liquid hydrocarbons in those instances where water may enter into the pipeline segment.

(c) Monitoring isolated segments.
(1) Monitoring procedures should be established based on the pressure, volumes, closures, and other pertinent factors.
(2) Personnel assigned to operate isolation equipment should have a means to determine pressure buildups, such as gauges and vents.
(3) Personnel monitoring at remote locations should have communication with the work site and the individual in charge of the operation.

4 NOTIFICATIONS PRIOR TO PURGE OR BLOWDOWN

4.1 Public officials.
Local public officials should be notified prior to a purge or blowdown in those situations where the normal traffic flow through the area might be disturbed, or where it is anticipated that there will be calls from the public regarding the purge or blowdown.

4.2 Public in vicinity of gas discharge.
The public in the vicinity of the gas discharge should be notified prior to a purge or blowdown, if it is anticipated that the public might be affected by the process. The primary considerations for determining the need for notification are noise, odor, and the possibility of accidental ignition.

5 REFERENCE

A reference is AGA XR603, "Plastic Pipe Manual for Gas Service," Chapter VI – Maintenance, Operation and Emergency Control Procedures.

§192.753

Caulked bell and spigot joints.

[Effective Date: 10/15/03]

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

(1) A mechanical leak clamp; or

(2) A material or device which:

(i) Does not reduce the flexibility of the joint;

(ii) Permanently bonds, either chemically or mechanically, or both, with the bell and spigot metal surfaces or adjacent pipe metal surfaces; and

(iii) Seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements of §§192.53(a) and (b) and 192.143.

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

[Amdt. 192-25, 41 FR 23679, June 11, 1976; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003]

GUIDE MATERIAL

No guide material necessary.

§192.755

Protecting cast-iron pipelines.

[Effective Date: 06/01/76]

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

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

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

(2) Impact forces by vehicles;

(3) Earth movement;

(4) Apparent future excavations near the pipeline; or

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

(b) As soon as feasible, appropriate steps must be taken to provide permanent protection for the disturbed segment from damage that might result from external loads, including compliance with applicable requirements of §§192.317(a), 192.319, and 192.361(b) — (d).

[Issued by Amdt. 192-23, 41 FR 13588, Mar. 31, 1976]

GUIDE MATERIAL

See guide material under §192.614, and Guide Material Appendices G-192-13, G-192-16, and G-192-18.

§192.756

Joining plastic pipe by heat fusion: equipment maintenance and calibration.

[Effective Date: 01/22/19]

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.

[Amdt 192-124, 83 FR 58694, Nov. 20, 2018]

1 GENERAL

(a) To comply with this regulation, operators should develop a maintenance and calibration plan using information from equipment manufacturers or from the operator's testing and experience, or both. The plan should address equipment that is used in heat-fusion joining of plastic pipe regardless of whether the equipment is owned, rented, or part of a contractor's fleet.

(b) For guidance related to equipment inspections, see 3.2 of the guide material under §192.281.

2 IDENTIFICATION OF EQUIPMENT AND MANUFACTURER RECOMMENDATIONS

(a) Identify the equipment used to complete the fusion process.
- (1) Butt fusion, saddle fusion, socket fusion, electrofusion equipment.
- (2) Facers used to prepare the pipe for joining.
- (3) Heaters.
- (4) Power sources, electrofusion only.

(b) Gather available information.
- (1) Equipment manuals.
- (2) Manufacturer information related to recommended maintenance and schedule intervals for maintenance of each type of equipment.
- (3) Manufacturer information related to recommended calibration activities.

3 MAINTENANCE AND CALIBRATION PLAN CONTENTS

(a) General plan contents.
- (1) A listing of the equipment covered by the plan.
- (2) Manufacturer maintenance recommendations and schedule intervals for each type of equipment.
- (3) Manufacturer calibration recommendations and schedule intervals for each type of equipment.
- (4) If the operator chooses to develop procedures for maintenance and calibration activities (as allowed in §192.756), include the following.
  - (i) Testing and experience information documenting that the procedures produce acceptable joints.
  - (ii) If a manufacturer recommends a more frequent interval than the procedure developed, document the testing and experience that supports the longer interval between maintenance and calibration activities.

(b) Special considerations – rented or contractor-owned equipment.
- (1) Detail how rented equipment and contractor-owned equipment will be uniquely identified within the operator's equipment record system, such as the following.
  - (i) Serial numbers.
  - (ii) Equipment asset numbers.
  - (iii) State registration information.
- (2) Define an inspection procedure for each type of equipment.
  - (i) The operator might choose to specify an "as received" inspection as well as an "as returned" inspection for rental equipment.

SUBPART N
QUALIFICATION OF PIPELINE PERSONNEL

<u>Cautionary Note:</u> Guide material in Subpart N is written specifically for the Regulations as adopted in Amendments 192-86, 192-90, and 192-100. Operators are advised that provisions in the Pipeline Safety Act of 2002 and Office of Pipeline Safety protocols for inspection need to be considered in their compliance with operator qualification.

§192.801
Scope.

[Effective Date: 10/26/99]

(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.**

[Issued by Amdt. 192-86, 64 FR 46853, Aug. 27, 1999]

GUIDE MATERIAL

See Cautionary Note at the beginning of Subpart N.

1 GENERAL

Guide material under this subpart provides direction for compliance with Subpart N, which covers operator qualification (OQ) of individuals who perform covered tasks on a pipeline facility. Operators of petroleum gas distribution systems or small gas systems (e.g., master meter operators) should review the “Small LP Gas Operator Guide" or the “Small Natural Gas Operator Guide” available at https://www.phmsa.dot.gov/training/pipeline/guidance-manuals.

2 CONTRACTORS

(a) In implementing its OQ program, an operator should consider that any contractor individual who performs covered tasks on the operator's behalf needs to be qualified unless the individual will be directed and observed by an individual that is qualified.

(b) An operator should consider including provisions in its own written program to address the use of contractor or mutual aid employees performing covered tasks.

(c) It may be necessary for an operator to work with the contractor or mutual aid employee to ensure that qualifications are established and maintained consistent with the operator's program.

3 EMERGENCY RESPONSE

An operator should plan to use individuals who are qualified under its OQ program for emergency response for tasks that meet the four-part test in §192.801(b).

SUBPART O
GAS TRANSMISSION PIPELINE INTEGRITY MANAGEMENT

§192.901
What do the regulations in this subpart cover?

[Effective Date: 02/14/04]

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.

[Issued by Amdt. 192-95, 68 FR 69778, Dec. 15, 2003 with Amdt. 192-95 Correction, 69 FR 2307, Jan. 15, 2004]

GUIDE MATERIAL

1 GENERAL

The requirements of Subpart O apply to all transmission pipelines including compressor stations, metering stations, regulator stations, valve sets, and other fabricated assemblies. The requirements of Subpart O do not apply to distribution lines or to gathering lines.

2 APPLICABILITY OF THIS SUBPART

Table 192.901i identifies the applicability of each section of Subpart O to plastic line pipe, steel line pipe and pipeline components. In the table, "Components" refers to gas-carrying components other than line pipe that are typically above ground, such as compressor stations, meter stations, and regulator stations.

APPLICABILITY OF SUBPART O						
	Gas Transmission Pipeline System					
	Covered Segment (see §192.903)			Non-Covered Segment		
Regulation Section	Plastic Line Pipe	Steel Line Pipe	Components	Plastic Line Pipe	Steel Line Pipe	Components
192.901	R	R	R	R	R	R
192.903	R	R	R	R	R	R
192.905	R	R	R	R	R	R
192.907	R	R	R	C	C	C
192.909	R	R	R	NA	NA	NA
192.911	C	R	R	NA	NA	NA
Legend: R = Required; C = Consider; NA = Not Applicable						

TABLE 192.901i

assessment.

[Issued by Amdt. 192-95, 68 FR 69778, Dec. 15, 2003 with Amdt. 192-95 Correction, 69 FR 2307, Jan. 15, 2004]

GUIDE MATERIAL

1 SUPERVISORY PERSONNEL QUALIFICATIONS

1.1 General.

The Integrity Management Program (IMP) should define the minimum training, qualification, or experience required for supervisory personnel whose responsibilities relate to the IMP. Supervisory personnel can acquire thorough knowledge of the IMP by achieving the following.

(a) General understanding of, and familiarity with, the overall program; and
(b) Specific knowledge in their respective areas of responsibility.

1.2 Gaining general understanding.

Examples of means used to gain general understanding of the IMP include the following.

(a) Conducting periodic review of the written program.
(b) Training or orientation sessions.
(c) Conducting peer reviews.
(d) Using a list of subject matter experts that can be contacted for additional details.

1.3 Demonstrating specific knowledge.

Examples of means used to demonstrate specific knowledge of an individual’s area of responsibility include the following.

(a) Internal and external training records.
(b) Experience résumés.
(c) Licenses or certifications.
(d) Continuing educational credits.
(e) Qualification records.
(f) Authored papers or articles that have been published.
(g) Documented experience in developing standards and procedures.
(h) Copies of presentations given to public, industry, or an operator’s internal groups.
(i) Regulatory testimony.

2 OTHER QUALIFICATIONS

2.1 Personnel who require qualification.

In accordance with §192.915(b) and (c), the IMP must define the qualification criteria (e.g., knowledge, skills, abilities) for operator and contractor personnel who do the following.

(a) Perform assessments.
(b) Evaluate assessment results.
(c) Analyze and integrate data.
(d) Make technical decisions based upon assessment results (e.g., dig locations, repair methods, prioritization of fieldwork).
(e) Implement preventive and mitigative measures.
(f) Supervise excavation work associated with assessments.

For qualification of personnel performing ILI assessments, see Guide Material Appendix G-192-14.

2.2 Demonstrating qualifications.

Examples of means used to demonstrate qualification of employees and contractors include the

following.
(a) Training records.
(b) Documented experience.
(c) Qualification records.
(d) Certifications from industry organizations.
(e) Education records.
(f) Quality assurance information required by §192.911(l).

3 DOCUMENTATION

The operator might consider developing a matrix of integrity management related tasks, which outline the qualification requirements, and what operator or contractor position may perform each task.
(a) Documentation of the knowledge and training of integrity management personnel should demonstrate the following in accordance with the IMP.
  (1) Competence in performing the assigned IMP element.
  (2) Awareness of the IMP requirements.
  (3) The process used to qualify the person for the IMP element.
(b) Operators using contractors in the IMP should document that the contractor employees are aware of and qualified for the applicable sections of the operator's IMP.

4 ADDITIONAL INFORMATION

See OPS Advisory Bulletin ADB-2017-02 (82 FR 17152, April 10, 2017; reference Guide Material Appendix G-192-1, Section 2).

§192.917

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

[Effective Date: 05/24/23]

(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 threat 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 data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. Operators must begin to integrate all pertinent data elements specified in this section starting on May 24, 2023, with all

available attributes integrated by February 26, 2024. 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,

(b) The test water contains bacteria that promote MIC.

4.7 *Gas, liquid, and solid sampling analysis.*
Analysis of gas, liquid, and solid samples can be used to help determine the probability of internal corrosion and help identify the cause of corrosion. Data should be trended to determine if values are increasing or decreasing.

(a) Gas. When analyzing for internal corrosion, partial pressures (see 4.10 below) and gas chemistry are important considerations. Typical gas analysis should include the determination of the following constituents.

(1) *Carbon dioxide (CO_2).* CO_2 in the gas can mix with water in the gas stream to form carbonic acid, which is corrosive to steel. The percentage of CO_2 in the gas stream can be determined by using a stain tube or analyzing the sample by gas chromatography. CO_2 partial pressure below 3 psia is generally considered non-corrosive. See 16.1.4 and 16.1.5 below. The table below identifies typical concern levels for CO_2 partial pressures.

CO_2 Partial Pressure (psia)	Level of Concern
< 3	Low Risk
3 – 30	Moderate Risk
> 30	High Risk

TABLE 192.917i

(2) *Hydrogen sulfide (H_2S).*

(i) H_2S may be a normal constituent in gas, and can also be formed due to MIC. H_2S will combine with water to form a weak sulfuric acid which is corrosive to steel. The presence of H_2S may also cause hydrogen blistering and sulfide stress cracking.

(ii) The amount of H_2S in the gas stream may be determined by using a stain tube or an electronic meter. The stain tube typically provides a read out in ppm which, if necessary, is then converted to percentage. Electronic meters give a direct reading of the percent of H_2S in the gas.

(iii) A typical operator-set tariff range for H_2S is between 4 and 16 ppm. Gas maintained at tariff quality is considered a low concern for internal corrosion caused by H_2S.

(3) *Oxygen (O_2).* O_2 is often present in small amounts in gas and, when present in a gas stream containing water, can act as a catalyst to speed up general and pitting corrosion. O_2 can be measured with a stain tube or by gas chromatography. If O_2 is indicated, the dissolved O_2 concentration in water should be calculated. A dissolved O_2 concentration above 10 to 50 ppm is considered corrosive to steel pipelines.

(4) *Water content or dew point.* For corrosion to occur there must be an electrolyte, such as water, present to react with the gas constituents. High dew points may allow water to condense at certain locations and activate corrosion mechanisms. Water content in the gas stream can be measured with either a stain tube or an electronic meter. Both devices determine the amount of water in pounds per million cubic feet (lbs/MMSCF) of the gas. A value of less than 7 lbs/MMSCF is generally considered non-corrosive. At higher concentrations and certain pressure and temperature conditions, it is possible for water vapor to condense.

(b) Liquid. For evaluating internal corrosion, only liquids containing electrolytes need to be analyzed. Non-electrolytes, such as drip gas and other hydrocarbons, may not need to be analyzed because they do not contribute to corrosion. Water indicators are available to determine if the sample contains electrolytes. When analyzing for internal corrosion, a typical liquid analysis includes the following.

(1) *pH.* The pH measures the acidity or alkalinity. A pH of 7 is neutral. A reading of less than 7 is acidic, with lower numbers indicating a stronger acid. Readings above 7 are alkaline,

with higher numbers indicating a stronger base. Readings near neutral represent less corrosive liquids. Low pH levels, such as 5.0 or less, may result in increased corrosion.

(2) *Iron or manganese.*

(i) Iron might exist naturally in liquids in small amounts. Manganese is not normally present in liquids produced from gas sources, but is present in steel.

(ii) Iron concentrations above 2500 ppm or manganese concentrations above 25 ppm may indicate corrosion of steel. A manganese to iron ratio between 1:50 and 1:200 may indicate the source of iron is from corrosion. Deviations from this ratio range could indicate the presence of other material or other chemical mechanisms. See 16.1.6 below.

(iii) Due to precipitation of iron from the liquid sample, a lower iron concentration in solution may not indicate a reduced rate of corrosion. Proper handling of samples should be ensured to prevent precipitation.

(iv) When analyzing iron and manganese counts, the system parameters (e.g., flow rate, amount of water, temperature) should be reviewed and scaling tendency should be determined.

(3) *Salt or chlorides.* Salt, or more specifically chloride, is not in itself corrosive. Water containing chlorides or other salts tend to be more corrosive than fresh water. The type and concentration of anions in the sample can be used to predict acceleration of corrosion activity (e.g., when chloride ions are present) or inhibition of corrosion activity.

(c) Solids. Solids should be sampled whenever they are found inside the pipe. Bacteria cultures (see 4.8 below) and pH need to be taken immediately upon exposing the solids, because the values may change when exposed to air. A typical solid analysis includes the following.

(1) *Iron sulfide (FeS_2).* Iron sulfide is a byproduct of the reaction of H_2S and steel, and is also produced by sulfate reducing bacteria. It may be identified as the mineral pyrite or marcasite. Iron sulfide often coats the internal surface of pipe, but because iron sulfide is cathodic to steel, breaks in the scale may often cause acceleration of pitting.

(2) *Mineral scale.* Mineral scale may contain a variety of components and compounds, depending on the contaminants and environment. Scale should be examined to determine actual composition, which may suggest corrosion mechanisms. Mineral scale might include salt, calcium and other carbonates, sulfide minerals, as well as a variety of iron minerals. Iron found in a solid sample that has accumulated in vessels, loosened during cleaning pig runs, or debris found when a cutout is made on the line typically represents corrosion product. When evaluating for iron, manganese should also be evaluated.

(3) *Erosive material.* Material and other debris, such as sand, quartz, and black powder, might be present in pipeline solids and may create erosion corrosion issues.

4.8 Bacteria culture tests.

Liquids and solids collected should be tested for the presence of both acid-producing bacteria (APB) and sulfate-reducing bacteria (SRB) through the use of culture tests. The presence of bacteria in the system does not necessarily indicate that MIC is occurring. However, further investigation needs to be performed.

4.9 Internal probes or coupons.

Internal probes or corrosion coupons may be used to indicate the presence of internal corrosion. These weight loss devices provide an indication of the corrosion rate in mils per year.

4.10 Operating parameters.

Operating parameters include the following.

(a) Temperature. The temperature of the gas or liquid present in the pipeline will affect the corrosion rate. In general, each 18 °F temperature increase will double reaction rates. The temperature of both the gas and liquid phases are important. In addition, locations that cool the gas (e.g., crossings of streams, rivers, and swamps) or changes in flow or pressure may cause a condensation of liquids.

(b) Flow rates. Low flow rates may not effectively sweep the pipeline of liquids or other debris. Flow rates should be considered where there are changes in pipe diameters, low spots, or other potential liquid collection locations along the pipeline.

(c) Flow direction. Bidirectional flow or flow reversal may impact the location and the rate of internal corrosion.

(d) Changes in source of gas. Source and location changes of gas entering a transmission line might change the composition of the gas stream.

(e) Pressure. The operating pressure is used to calculate partial pressures for the constituents. The partial pressure of a constituent determined in 4.7 is dependent on the amount of the constituent and the operating pressure of the pipeline. The partial pressure of a gas is calculated by multiplying the mole fraction of the component by the pipeline pressure converted to absolute pressure (psia).

For example, if the mole fraction of CO_2 is 1.2% and the operating pressure of the pipeline is 200 psig (214.7 psia), the partial pressure is 0.012 x 214.7 psia = 2.6 psia, and CO_2 is not likely to cause corrosion. If the operating pressure is 2000 psig (2014.7 psia), the same CO_2 percent would yield a partial pressure of 24.2 psia (0.012 x 2014.7 psia = 24.2 psia), which is more likely to cause internal corrosion.

4.11 Operating stress level.

Operating stress level is a key factor in predicting failure mechanisms and determining the tolerance to internal corrosion. Flow reversals might change the pressure gradient of a pipeline by affecting the operating stress level at different points along the pipeline. The effect of new pressure gradient on existing defects should be evaluated.

4.12 Other considerations.

In addition to the data elements listed in ASME B31.8S, Appendix A2, the following data may be useful in evaluating corrosion.

(a) The factors listed in guide material under §192.476 regarding internal corrosion include the following.
  (1) Liquid removal facilities, such as drips, siphons, or dehydrators.
    (i) Type of liquid removal facility and locations.
    (ii) The quantity of liquids removed from the facility.
    (iii) The frequency of liquid removal.
  (2) Pipeline profile and configuration (e.g., low spots, dead legs, other locations where liquid could collect).

(b) Critical angle analysis can be used to evaluate internal corrosion as a threat. See 5 of the guide material under §192.927.

(c) History of upset conditions which could have introduced corrosive constituents into the gas stream.

(d) Chemical treatments (e.g., corrosion inhibitors, biocides), including the types of chemicals used for treatment, frequency of treatment, and how the treatment was administered (e.g., continuous or batch).

(e) The presence and condition of internal coatings.

(f) Pigging and other cleaning history.

(g) Incident and safety-related condition reports related to internal corrosion.

5 STRESS CORROSION CRACKING

(a) In evaluating the threat of stress corrosion cracking (SCC), ASME B31.8S, Appendix A3 provides a list of data that the operator is required to gather and evaluate. Additional information can also be found in guide material under §192.613, and the reference listed in 16.1.7 below. Pipeline segments may be susceptible to two types of SCC; high pH and near-neutral pH.

(b) SCC requires three conditions to be satisfied simultaneously:
  (1) a tensile stress above the threshold stress,

10.3 Failures caused by incorrect operations.

Failures or potential failures caused by an incorrect operation may be found in the following reports.

(a) Abnormal operations.
(b) Safety-related conditions.
(c) Root-cause analysis.
(d) Incidents.
(e) Near misses.
(f) OQ disqualifications.

11 WEATHER AND OUTSIDE FORCES

Weather-related and outside force threats have the capability to create extreme loading conditions on pipelines. In assessing this type of threat, ASME B31.8S, Appendix A9 provides a list of data that the operator is required to gather and evaluate to determine whether pipelines are being subjected to extreme loading conditions caused by weather or outside forces. Aboveground facilities are also prone to weather-related events. See Guide Material Appendix G-192-13 for additional information on possible geological threats that can create outside forces upon a pipeline.

11.1 Pipe joining method.

Pipelines with the following joint types are more susceptible to leakage or failure from the threat of weather-related and outside forces than pipelines constructed using modern joining methods.

(a) Mechanical fittings that do not have restraints to prevent pipe pull-out.
(b) Oxyacetylene welds, due to their brittleness.
(c) Miter joints.

11.2 Topography, soil conditions, and frost depth.

The following topographical areas should be examined to determine if they contribute to this threat by exerting extreme loading conditions (e.g., bending, tension, compression).

(a) Slopes prone to movement or other unstable areas that would induce additional stress in a pipeline due to the movement of soil.
(b) Extremely saturated soils that produce buoyant forces on pipelines.
    (1) River and stream crossings.
    (2) Lowlands, floodplains, and swamps.
    (3) Coastal areas prone to tidal surges from hurricanes or tropical storms.
(c) Areas susceptible to frost heave.
(d) Highly expansive or unstable soils (e.g., some clays or manmade soils).
(e) Locations with known geologic conditions that contribute to instability (e.g., karst topography, sinkholes, underground mining, other subsidence areas).

11.3 Fault zones.

The following should be considered in evaluating an active or known fault zone.

(a) Location of earthquake fault lines.
(b) Previous earthquake activity.
(c) Probability of future earthquake activity along fault.
(d) Analyses of leaks or damage attributable to earthquake activity.

11.4 Year of installation.

Older pipeline facilities were constructed with materials and techniques that are generally not equivalent to modern facilities in terms of strength and integrity. The risk attributable to weather-related and outside force threats may be commensurate with the age of the pipeline facilities. If the installation data is not known, conservative estimates of the installation year can be used.

11.5 Pipe parameters.

The following pipe parameters are factors in determining operating hoop stress

(iii) Knowledge of operator's applicable procedures, including emergency response.
(iv) Understanding the risks of various excavation methods.
(4) Other activities that could adversely affect the integrity of the pipeline.
(b) Use a central database to collect the following.
(1) Excavation damage information for covered and non-covered segments. This might include the following.
(i) Number of leaks or ruptures.
(ii) Number of known damages not resulting in leaks or ruptures.
(iii) Excavation method.
(iv) Name of excavator causing damage.
(2) Root-cause analysis data to identify targeted P&M measures for HCAs. This might include the number of damages where:
(i) No line locate was requested.
(ii) Line was incorrectly marked.
(iii) Line was not marked.
(iv) Construction procedures were not followed correctly (e.g., exposing lines during boring).
(3) Damage data that is not DOT reportable (reference Part 191 requirements). This might include known items such as the following.
(i) Dents.
(ii) Gouges.
(iii) Coating damage.
(iv) Damage to pipeline supports or river anchors.
(c) Participate in a one-call program wherever there are covered segments.
(d) Monitor excavations on covered segments. An operator may want to consider the following.
(1) Mapping HCAs so field personnel can easily recognize when they are in an area that requires monitoring.
(2) Creating a business process that alerts the appropriate departments of pending excavations.
(3) Working with the local One-Call Center to notify excavators and operators when monitoring is required.
(4) Training line locators to notify appropriate personnel when they know work will take place in an HCA.
(5) Documenting excavation monitoring using one or more of the following.
(i) Time card accounting.
(ii) Special forms.
(iii) Time-stamped electronic data.
(iv) Maps.
(e) When there is physical evidence of an excavation near a covered segment that the operator did not monitor, either excavate the area or conduct an aboveground survey (e.g., DCVG) as defined in NACE SP0502(see §192.7 for IBR). Examples of how to identify an encroachment might include the following.
(1) New pavement patches.
(2) Heavy equipment on site.
(3) Disturbed earth.
(4) New structures requiring excavation (e.g., fence posts, telephone poles, buildings, slabs).
(5) Exposed pipe.
(6) New landscaping.
(7) One-call documentation.

3 OUTSIDE FORCE DAMAGE (§192.935(b)(2))

To comply with §192.935(b)(2) for the specific threat of outside force damage (e.g., earth movement or other geological hazards, floods, unstable suspension bridge), an operator must take additional measures to minimize the consequences of outside force.
(a) The measures include the following.
(1) Increasing the frequency of patrols to allow faster for recognition of damage.
(2) Adding external protection. This might include the following.

(i) Installing fencing or other barriers to impede earth movement.
(ii) External slabs or additional cover.
(iii) Add erosion protection such as riprap.
(3) Reducing external stress. This might include the following.
(i) Installing expansion joints.
(ii) Removing overburden.
(4) Relocating the pipeline to an area with less exposure to outside forces. This might include lowering or raising the pipeline. Horizontal directional drilling, when feasible, might avoid stresses caused by geological hazards.
(5) Conducting inline inspections to determine whether geometric deformation has occurred.
(6) Installing dewatering or drainage best management practices (e.g., drain tile, coconut boom, vegetation, trenching)
(7) For additional guidance on protection from outside forces, see Guide Material Appendix G-192-13.

(b) An operator might also consider installing the following.
(1) River anchors where appropriate.
(2) Elevated relief or vent stacks on regulator stations.
(3) Additional bridge hangers or pipe supports.
(4) Identifying geodetic monitoring points (e.g., survey benchmarks) to track potential ground movement.
(5) Installing slope inclinometers to track ground movement at depth which might otherwise not be detectable during ROW patrols.
(6) Installing standpipe piezometers to track changes in groundwater conditions that might affect slope stability.
(7) Evaluating the accumulation of strain in the pipeline by installing strain gauges on the pipeline.
(8) Conducting stress-strain analysis using in-line inspection tools equipped with inertial mapping unit technology and high-resolution deformation in-line inspection for pipe bending and denting from movement.
(9) Using aerial mapping light detection and ranging (LiDAR) or other technology to track changes in ground conditions.

4 PIPELINES OPERATING BELOW 30 PERCENT SMYS (§192.935(d))

Pipelines operating below 30% SMYS have additional requirements as addressed below. For guidance related to these additional requirements, see Appendix E to Part 192.
(a) For all Class locations in an HCA, the following apply.
(1) Qualify personnel to conduct the following activities related to work the operator is conducting in a covered segment.
(i) Locating the pipeline.
(ii) Marking the pipeline.
(iii) Directly supervising known excavation work. A qualification for this activity might include the following.
(A) Recognition of line-locate markings.
(B) Knowledge of one-call requirements.
(C) Knowledge of operator's applicable procedures, including emergency response.
(D) Understanding the risks of various excavation methods.
(iv) Other activities that could adversely affect the integrity of the pipeline.
(2) Participate in a one-call program wherever there are covered segments.
(3) Either monitor excavations near the pipeline, or conduct patrols on a bi-monthly frequency. Any indication of unreported construction activity requires an investigation to determine if any damage has occurred.
(b) For Class 3 or Class 4 locations outside of an HCA.
(1) Qualify personnel to conduct the following activities related to work the operator is conducting in covered segment.
(i) Locating the pipeline.

(ii) Marking the pipeline.
(iii) Directly supervising known excavation work. A qualification for this activity might include the following.
(A) Recognition of line-locate markings.
(B) Knowledge of one-call requirements.
(C) Knowledge of operator's applicable procedures, including emergency response.
(D) Understanding the risks of various excavation methods.
(iv) Other activities that could adversely affect the integrity of the pipeline.
(2) Participate in a one-call program wherever there are covered segments.
(3) Either monitor excavations near the pipeline, or conduct patrols on a bi-monthly frequency. Any indication of unreported construction activity requires an investigation to determine if any damage has occurred.
(4) Perform semi-annual leak surveys. For unprotected or cathodically protected pipe where electrical surveys are impractical, perform quarterly leak surveys.
(c) See Table 192.935i.

GUIDE MATERIAL APPENDIX G-191-2

(See guide material under §§191.9, 191.11, 191.13, 191.15, and 191.17)

INDEX OF PHMSA REPORT FORMS

This appendix is an index of PHMSA forms and the code sections in which they are referenced.

PHMSA Form Number*	Form Title	Code Section(s) Referencing the Form
F 1000.1	OpID Assignment Request	191.21, 191.22
F 1000.2	National Registry Notification	191.22
F 7100.1	Gas Distribution System (Incident Report)	191.9, 191.21
F 7100.1-1	Gas Distribution System (Annual Report)	191.11, 191.21
F 7100.2	Gas Transmission and Gathering Systems (Incident Report) **	191.15, 191.21
F 7100.2.2	Type R (Reporting – Regulated) Gas Gathering Systems (Incident Report)	191.9, 191.13, 191.15
F 7100.2-1	Gas Transmission and Gathering Systems (Annual Report)	191.17, 191.21, 192.945
F 7100.2-3	Type R (Reporting – Regulated) Gas Gathering Pipeline Systems (Annual Report)	191.11, 191.13, 191.17
F 7100.3	Liquefied Natural Gas (LNG) Facilities (Incident Report)	191.15, 191.21
F 7100.3-1	Liquefied Natural Gas (LNG) Facilities (Annual Report)	191.17, 191.21
F 7100.4-1	Underground Natural Gas Storage Facility (Annual Report)	191.17

* Latest versions of forms and instructions are available at www.phmsa.dot.gov/forms/pipeline-forms.
** Includes underground natural gas storage.

1.14 OTHER DOCUMENTS (Continued)		
GRI-91/0285.1	Executive Summary: Technical Summary and Database for Guidelines for Pipelines Crossing Railroads and Highways	GMA G-192-15
GRI-95/0171	State-of-the-Art Review and Analysis of Guided Drilling Systems	GMA G-192-15B
GRI-96/0368	Guidelines for the Application of Guided Horizontal Drilling to Install Gas Distribution Pipe	GMA G-192-15B
IAPMO	Uniform Plumbing Code	§192.141
INGAA Foundation Report 2015-03	Mitigation of Land Movement in Steep and Rugged Terrain for Pipeline Projects: Lessons Learned from Constructing Pipelines in West Virginia.	§192.103 GMA G-192-13
ISO 31000	Risk Management – Guidelines	§192.12
ISO 31010	Risk Management – Risk assessment techniques	§192.12
ISO 55000	Asset Management	§192.12
Nature Conservancy	Improving Steep-Slope Pipeline Construction to Reduce Impacts to Natural Resources	GMA G-192-13
NCB	Subsidence Engineers' Handbook, National Coal Board Mining Department (U.K.), 1975	GMA G-192-13
NFPA 10	Portable Fire Extinguishers	
NFPA 14	Installation of Standpipe and Hose Systems	§192.141
NFPA 24	Installation of Private Fire Service Mains and Their Appurtenances	§192.141
NFPA 54/ANSI Z223.1	National Fuel Gas Code	Figure 192.11A Figure 192.11B §192.629
NFPA 220	Types of Building Construction	
NFPA 224	Homes and Camps in Forest Areas (Discontinued)	§192.163
NFPA 921	Guide for Fire and Explosion Investigations	§192.617
OTD-12/0003	Cross Bore Best Practices – Best Practices Guide (prepared by GTI)	§192.614 GMA G-192-6
PRCI L22279	Further Studies of Two Methods for Repairing Defects in Line Pipe	§192.713
PRCI L51406	Pipeline Response to Buried Explosive Detonations	GMA G-192-16
PRCI L51574	Non-Conventional Means for Monitoring Pipelines in Areas of Soil Subsidence or Soil Movement	GMA G-192-13
PRCI L51717	Pipeline In-Service Relocation Engineering Manual	§192.703

Table Continued		
1.14 OTHER DOCUMENTS		
PRCI L51725	Drilling Fluids in Pipeline Installation by Horizontal Directional Drilling-A Practical Applications Manual	GMA G-192-15A GMA G-192-15B
PRCI L51740	Evaluation of the Structural Integrity of Cold Field-Bent Pipe	§192.313
PRCI L52047	Pipeline Repair Manual (PR-218-9307)	§192.613 §192.713 §192.929
PRCI PC-PISCES	Personal Computer - Pipeline Soil Crossing Evaluation System (PC-PISCES), Version 2.0 (Related to API RP 1102)	GMA G-192-15
PRCI PR-000-18COMP-R04	Geohazards Compendium	§192.103 GMA G-192-13
PRCI PR-277-144507	Installation of Pipelines Using Horizontal Directional Drilling – An Engineering Design Guide	GMA G-192-15A GMA G-192-15B
PRCI PR-430-153706-R01	Hydrostatic Test Guidelines for Integrity Management	GMA G-192-9A
UL 723	Test for Surface Burning Characteristics of Building Materials	§192.163

2 GOVERNMENTAL DOCUMENTS

Note: NTSB Reports are available at
https://www.ntsb.gov/investigations/AccidentReports/Pages/Reports.aspx?mode=Pipeline
OPS Advisory Bulletins and Alert Notices are accessible as follows.
- PHMSA-OPS website at www.phmsa.dot.gov/regulations-fr/notices
- Federal Register (FR) at
  https://www.gpo.gov/fdsys/search/submitcitation.action?publication=FR or at
  www.federalregister.gov/documents/search#

BSEE Report RLS011	Cement Plug Testing: Weight vs pressure Testing to Assess Viability of a Wellbore Seal between Zones	§192.12
DHS	Recommended Practice: Improving Industrial Control System Cybersecurity with Defense-in-Depth Strategies. Industrial Control Systems Cyber Emergency Response Team (September 2016).	§192.631
DOT & DOI - MOU	Memorandum of Understanding Between DOT and DOI Regarding Outer Continental Shelf Pipelines	§191.1 §192.1 GMA G-192-19
NAPSR	Compendium of State Pipeline Safety Requirements & Initiatives Providing Increased Public Safety Levels Compared to Code of Federal Regulations	§191.1 §192.1
NEB MH-2-95	Stress Corrosion Cracking on Canadian Oil and Gas Pipelines, Report of the Inquiry, National Energy Board, December 1996	§192.613 §192.929
NTSB Report MAR-21-05	Marine Accident Report - Hazardous Liquid Pipeline Strike and Subsequent Explosion and Fire aboard Dredging Vessel *Waymon Boyd,* Corpus Christi, Texas, August 21, 2020	GMA G-192-13
NTSB Report PAB-98-02	Pipeline Accident Brief – Fire and Explosion, Midwest Gas Company, Waterloo, Iowa, October 17, 1994	§192.613
NTSB Report SIR-98-01	Special Investigation Report – Brittle-Like Cracking in Plastic Pipe for Gas Service	§192.613
OPS ADB-03-03	Advisory Bulletin – Identified Sites for Possible Inclusion as High Consequence Areas (HCAs) in Gas Integrity Management Programs (68 FR 42458, July 17, 2003)	§192.905
OPS ADB-03-05	Advisory Bulletin – Stress Corrosion Cracking (SCC) Threat to Gas and Hazardous Liquid Pipelines (68 FR 58166, Oct. 8, 2003)	§192.613 §192.929
OPS ADB-04-01	Advisory Bulletin – Hazards Associated with De-Watering of Pipelines (69 FR 58225, Sept. 29, 2004)	§192.515
OPS ADB-06-01	Advisory Bulletin – Notification on Safe Excavation Practices and the use of Qualified Personnel to oversee all Excavations and Backfilling Operations (71 FR 2613, Jan. 17, 2006)	§192.605 §192.614 §192.805

2 GOVERNMENTAL DOCUMENTS (Continued)		
OPS ADB-07-01	Advisory Bulletin – Senior Executive Signature and Certification of Integrity Management Program Performance Reports (72 FR 20175, Apr. 23, 2007)	§192.951
OPS ADB-07-02 [Shown as ADB-07-01 in text]	Advisory Bulletin – Updated Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe (72 FR 51301, Sept. 6, 2007 with Correction, 73 FR 11192, Feb. 29, 2008)	§192.613 §192.917
OPS ADB-08-02	Advisory Bulletin – Issues Related to Mechanical Couplings Used in Natural Gas Distribution Systems (73 FR 11695, Mar. 4, 2008)	§192.281
OPS ADB-08-03	Advisory Bulletin – Dangers of Abnormal Snow and Ice Build-Up on Gas Distribution Systems (73 FR 12796, Mar. 10, 2008)	§192.616
OPS ADB-09-01	Advisory Bulletin – Potential Low and Variable Yield and Tensile Strength and Chemical Composition Properties in High Strength Line Pipe (74 FR 23930, May 21, 2009)	§192.917
OPS ADB-10-03	Advisory Bulletin – Girth Weld Quality Issues Due to Improper Transitioning, Misalignment, and Welding Practices of Large Diameter Line Pipe (75 FR 14243, Mar. 24, 2010)	§192.620
OPS ADB-10-08	Advisory Bulletin – Emergency Preparedness Communications (75 FR 67807, Nov. 3, 2010)	§192.615
OPS ADB-11-02	Advisory Bulletin – Dangers of Abnormal Snow and Ice Build-Up on Gas Distribution Systems (76 FR 7238, Feb. 9, 2011)	§192.616
OPS ADB-86-02	Advisory Bulletin – Plastic Piping, Mechanical Coupling (Feb. 26, 1986; see document at PHMSA-OPS website)	§192.917
OPS ADB-93-01	Advisory Bulletin – Snow Accumulation on Gas Pipeline Facilities (58 FR 7034, Feb. 3, 1993)	§192.616
OPS ADB-97-01	Advisory Bulletin – Potential Damage to Pipelines by Impact of Snowfall, and Actions Taken by Homeowners and Others to Protect Gas Systems from Abnormal Snow Build-up (Issued in Kansas City, MO on Jan. 24, 1997)	§192.616
OPS ADB-99-01	Advisory Bulletin – Susceptibility of Certain Polyethylene Pipe Manufactured by Century Utility Products, Inc. to Premature Failure Due to Brittle-Like Cracking (64 FR 12211, Mar. 11, 1999)	§192.613 §192.917
OPS ADB-99-02	Advisory Bulletin – Potential Susceptibility of Plastic Pipe Installed Between the [Years] 1960 and the Early 1980s to Premature Failure Due to Brittle-Like Cracking (64 FR 12212, Mar. 11, 1999)	§192.613 §192.917

2 GOVERNMENTAL DOCUMENTS (Continued)		
OPS ADB-99-04	Advisory Bulletin – Directional Drilling and Other Trenchless Technology Operations Conducted in Proximity to Underground Pipeline Facilities (64 FR 46967, Aug. 27, 1999)	GMA G-192-15B
OPS ADB-2012-02	Advisory Bulletin – Post-Accident Drug and Alcohol Testing (77 FR 10666, Feb. 23, 2012)	§192.605 §192.615
OPS ADB-2012-03	Advisory Bulletin – Notice to Operators of Driscopipe® 8000 High Density Polyethylene Pipe of the Potential for Material Degradation (77 FR 13387, Mar. 6, 2012)	§192.613 §192.917
OPS ADB-2012-07	Advisory Bulletin – Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe (67 FR 70806, Nov. 26, 2002 with Correction, 67 FR 72027, Dec. 3, 2002)	§192.613 §192.917
OPS ADB-2012-08	Advisory Bulletin – Inspection and Protection of Pipeline Facilities after Railway Accidents (77 FR 45417, July 31, 2012)	§192.615
OPS ADB-2012-10	Advisory Bulletin – Using Meaningful Metrics in Conducting Integrity Management Program Evaluations (77 FR 72435, Dec. 5, 2012)	GMA G-192-3
OPS ADB-2012-11	Advisory Bulletin – Reporting of Exceedances of Maximum Allowable Operating Pressure (77 FR 75699, Dec. 21, 2012)	§191.23
OPS ADB-2014-03	Advisory Bulletin – Construction Notification (79 FR 54777, Sept. 12, 2014	§191.22
OPS ADB-2014-05	Advisory Bulletin – Guidance for Strengthening Pipeline Safety Through Rigorous Program Evaluation and Meaningful Metrics (79 FR 61937, Oct. 15, 2014)	GMA G-192-3
OPS ADB-2015-02	Advisory Bulletin – Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricanes (80 FR 36042, June 23, 2015)	§192.615
OPS ADB-2016-05	Advisory Bulletin – Clarification of Terms Relating to Pipeline Operational Status (81 FR 54512, August 16, 2016)	§192.727
OPS ADB-2016-6	Advisory Bulletin – Safeguarding and Securing Pipelines From Unauthorized Access (81 FR 89183, Dec 9, 2016).	§191.5 §192.179 §192.631
OPS ADB-2017-02	Advisory Bulletin – Guidance on Training and Qualifications for the Integrity Management Program, (82 FR 17152, April 10, 2017)	§192.915
OPS ADB-2019-01	Advisory Bulletin – Potential for Damage to Pipeline Facilities Caused by Severe Flooding (84 FR 14715, April 11, 2019)	§192.613 §192.615

2 GOVERNMENTAL DOCUMENTS (Continued)		
OPS ADB-2019-02	Advisory Bulletin – Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards (84 FR 18919, May 2, 2019)	§192.613
OPS ADB-2020-02	Advisory Bulletin – Pipeline Safety: Overpressure Protection on Low-Pressure Natural Gas Distribution Systems (85 FR 61097, September 29, 2020)	§192.195 §192.605 G-192-8
OPS ADB-2022-01	Advisory Bulletin – Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards (87 FR 33576, June 2, 2022)	§192.613
OPS ALN-88-01	Alert Notice – Operational failures of pipelines constructed with ERW prior to 1970 (Jan 28, 1988; see document at PHMSA-OPS website)	§192.917
USGS Report 2008-1164	Landslide and Land Subsidence Hazards to Pipelines.	§192.103
OPS ALN-89-01	Alert Notice – Update to ALN-88-01 (Mar 8, 1989; see document at PHMSA-OPS website)	§192.917
OPS-DOT.RSPA/DMT 10-85-1	Safety Criteria for the Operation of Gaseous Hydrogen Pipelines (Discontinued)	§192.1
OPS TTO No. 5	Technical Task Order – Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation, Michael Baker Jr., Inc., et al	§192.917
OPS TTO No. 8	Technical Task Order – Stress Corrosion Cracking Study, Michael Baker, Jr., Inc., January 2005	§192.613 §192.917 §192.929
PHMSA-OPS	Distribution Integrity Management: Guidance for Master Meter and Small Liquefied Petroleum Gas Pipeline Operators	GMA G-192-8
	Frequently Asked Questions (FAQs) on Gas Transmission Final Rule (Docket No. PHMSA-2019-0225, Sept. 15, 2020)	§192.607
	Gas Integrity Management Protocols	§192.925 §192.927
	Guidance Manual for Operators of LP Gas Systems	§192.1 §192.11 §192.616 GMA G-192-8
	Guidance Manual for Operators of Small Natural Gas Systems	§192.1 §192.616 GMA G-192-8
	Guidelines for Integrity Assessment of Cased Pipe for Gas Transmission Pipelines in HCAs	§192.925
	Guidance for Strengthening Pipeline Safety Through Rigorous Program Evaluation and Meaningful Metrics	GMA G-192-3
	"Interim Guidelines for Confirming Pipe Strength in Pipe Susceptible to Low Yield Strength for Gas Pipelines"	§192.620

2 GOVERNMENTAL DOCUMENTS (Continued)		
	Operator Qualification Guidance Manual for Operators of LP Gas Systems	§192.11 §192.801
	Operator Qualification Guide for Small Distribution Systems	§192.801
Transportation Security Administration	Pipeline Security Guidelines (March 2018) (https://www.tsa.gov/sites/default/files/pipeline_security_guidelines.pdf)	§191.5 §192.631

Table Continued

Site Reference (Continued)	**Website Link**	**Guide Location**
FEMA ICS overview	training.fema.gov/emiweb/is/icsresource	§192.615
GPTC website (for Technical Papers)	www.aga.org/GPTC	§192.361 §192.613 §192.907 GMA G-192-1
GTI website	www.gastechnology.org	GMA G-192-1
Hospitals	http://allhospitals.org	§192.905
IAPMO website	www.iapmo.org	GMA G-192-1
ICC (or BOCA) website	www.iccsafe.org	GMA G-192-1
IHS Markit website	www.ihsmarkit.com	GMA G-192-1
ILI Infodisk (SAI Global) website	https://www.saiglobal.com/	GMA G-192-1
MSS website	www.mss-hq.org	GMA G-192-1
NACE website	https://www.ampp.org/home	GMA G-192-1
NAP website	www.nap.edu or www.nap.edu/read/2347	GMA G-192-1 GMA G-192-13
NAPSR website	www.napsr.org	§191.1 §192.1 §192.18 §192.909
National Parks	www.recreation.gov	§192.905
NBBI website	www.nationalboard.org	GMA G-192-1
NCB website	www.coal.gov.uk	GMA G-192-1
NCIE website for National Maps	www.ncei.noaa.gov/access/monitoring/us-maps	GMA G-192-13
NFPA website	www.nfpa.org	GMA G-192-1
NRC pipeline reports website	https://nrc.uscg.mil/Default.aspx	§191.5
NTIS website	www.ntis.gov	GMA G-192-1
NTSB reports	https://www.ntsb.gov/investigations/AccidentReports/Pages/Reports.aspx?mode=Pipeline or www.ntsb.gov/safety/safety-studies/Pages/SafetyStudies.aspx	§192.613
NTSB website	www.ntsb.gov	GMA G-192-1
OPS Advisory Bulletins via FR	www.gpo.gov/fdsys/search/submitcitation.action?publication=FR	§192.905 GMA G-192-1
OPS Home Page	www.phmsa.dot.gov/pipeline	GMA G-192-1

Table Continued

Site Reference (Continued)	**Website Link**	**Guide Location**
OPS Information Resource Manager Email	InformationResourcesManager@phmsa.dot.gov	§192.727
OPS Integrity Management Database	primis.phmsa.dot.gov/gasimp	§192.907 §192.911
OPS NPMS homepage	www.npms.phmsa.dot.gov	§192.727
OPS Public Education	primis.phmsa.dot.gov/comm/PublicEducation.htm	§192.616
PHMSA-OPS Annual Report Data	www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids	GMA G-192-8
PHMSA-OPS Guidance Manuals	www.phmsa.dot.gov/training/pipeline/guidance-manuals	§192.1 §192.11 §192.616 §192.801 GMA G-192-8
PHMSA-OPS Guidance for Program Evaluation	www.regulations.gov/document?D=PHMSA-2014-0086-0002 *{then open the attachment}*	GMA G-192-3
PHMSA-OPS Guidance for Small DIMP	https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/gas-distribution-integrity-management/66011/phmsadimpsmalloperatorguidancerev1022813.pdf	GMA G-192-8
PHMSA-OPS Report Forms and Instructions	https://www.phmsa.dot.gov/forms/pipeline-forms	§191.9 §191.11 §191.15 §191.17 §192.945 GMA G-191-2 GMA G-192-8
PHMSA-OPS Underground Natural Gas Storage	www.phmsa.dot.gov/pipeline/underground-natural-gas-storage/underground-natural-gas-storage	§192.12
PPI website	www.plasticpipe.org	GMA G-192-1
PRCI website	www.prci.org	GMA G-192-1
SSPC website	www.sspc.org	GMA G-192-1
TTI website	https://technicaltoolboxes.com/	GMA G-192-1
UL website	www.ul.com	GMA G-192-1
US Government Publications	www.gpo.gov	GMA G-192-1
USGS Landslide Hazards Program website	www.usgs.gov/programs/landslide-hazards/maps	GMA G-192-13
Department of Homeland Security (DHS)'s National	http://ics-cert.us-cert.gov/sites/default/files/recommended_practice	§192.631

Cybersecurity and Communications Integration Center (NCCIC) and Industrial Control Systems Cyber Emergency Response Team (ICS-CERT)	s/NCCIC_ICS-CERT_Defense_in_Depth_2016_S508C.pdf	
Department of Homeland Security	www.cisa.gov/connect-plan-train-report	§191.613
Transportation Security Administration	https://www.tsa.gov/sites/default/files/pipeline_security_guidelines.pdf	§191.5 §192.631
Coastal and Marine Operators' Pipeline Industry Initiative	www.camogroup.org	§192.614 GMA G-192-13
Council for Dredging & Marine Construction Safety	https://cdmcs.org	§192.614 GMA G-192-13

13 SAMPLE PERFORMANCE MEASURES

Table 13.1 provides some potential performance measures for various programs common to gas systems. They are not all-inclusive nor should they be considered mandatory for performing a program effectiveness evaluation. The operator should choose only those measures (either suggested in the table or others applicable to the specific program) that are appropriate for the operator, system, and program being evaluated.

SAMPLE PERFORMANCE MEASURES	
Program	**Measure**
Transmission Integrity Management	See Tables in PHMSA "Guidance for Strengthening Pipeline Safety Through Rigorous Program Evaluation and Meaningful Metrics" and guide material under §192.945.
Distribution Integrity Management	See 7.2 in GMA G-192-8.
Public Awareness	*Outreach* – Measure outreach to stakeholders. - Number of website "visits" per time period. - Percent of stakeholders reached/total intended audience. - Use data such as the following. • Sent vs. opened emails. • Mail return rate. • Survey participation. • Meeting attendance rate.
	Understanding - Measure message comprehension and knowledge through surveys conducted by mail, email, telephone, or focus groups. Evaluate messages remembered vs. messages sent/read.
Public Awareness	*Behavior* - Measure stakeholders' behavior through the following. - Self-reported behavioral data in mail, email, or phone surveys. - Number of odor reports. - Number of locate requests to 811, State one-call center, or operator's call center.
	Bottom-line results - Measure bottom-line results by the following means. - Analyzing third-party incidents and one-call tickets. - Evaluating perception of operator's safety program and performance.
	Program-related measures - Annual audit, internal self-assessment. - External audit. - Corrective actions taken. - Updates/modifications to policies, processes, and procedures.

Table Continued

MISCELLANEOUS WELDING DETAILS

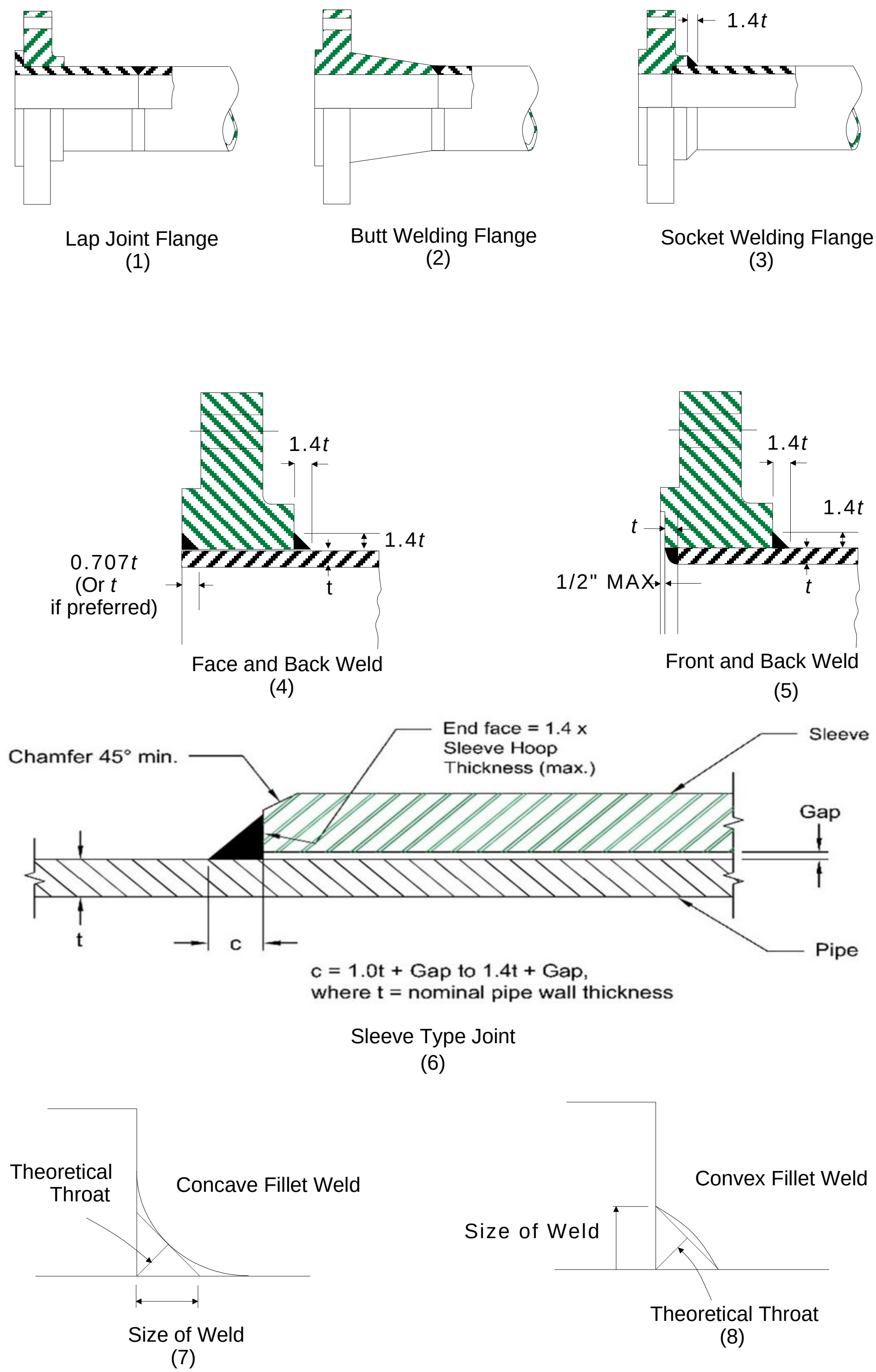


FIGURE 192.235C

4 IDENTIFY THREATS

4.1 Primary threats.

The primary threats to a gas distribution system are as follows and are generally described in the instructions for the DOT Annual Report, PHMSA Form F7100-1.1.

(a) Corrosion.
(b) Natural forces.
(c) Excavation damage.
(d) Other outside force damage.
(e) Material or welds.
(f) Equipment failure.
(g) Incorrect operation.
(h) Other.

An operator may subdivide the primary threats into subcategories to assess the relevance of a threat. An operator should also consider threats that could degrade the system over time (see 3.3(d) above). Operators who have system materials other than those specifically shown in Table 4.1 should also consider those different materials and analyze them relative to the primary threats.

4.2 Identify threats.

(a) One possible method for identifying applicable threats to a system that may be used is answering appropriate questions such as those in Table 4.1 and making the determination of whether the threat exists throughout the system (General) or is limited to a certain geographic region or material (Local). Some threats may be insignificant, non-existent, or not applicable (NA). These questions may or may not be applicable to all facilities or groups of facilities in an operator's system.
(b) The questions in Table 4.1 are not intended to be all-inclusive. They are provided to help the operator understand conditions that may indicate the possible presence of a particular threat. Operators are encouraged to ask as many questions as they determine are needed to define or eliminate a threat.
(c) Before the presence of a threat can be verified as applicable to the operator's distribution system, the operator should have "knowledge of the distribution system" as described in Section 3. Threats may vary based on the makeup and location of the system. For example, a plastic system does not experience a corrosion threat, an aging cast iron system may be prone to leakage at joints, and systems located in high-growth areas may experience an increased threat of excavation damage.
(d) The applicability of threats to an operator's distribution system may be identified by reviewing relevant operating and maintenance records (e.g., incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, one-call and excavation damage experience), considering knowledge of operating personnel, and evaluating relevant information. Operators may also use external sources of information, such as trade associations, other operators, manufacturers' recalls, PHMSA advisory bulletins, or other recommendations.

4.3 Sample threat identification method.

Attention can be focused on certain facilities or groups of facilities by first determining if one or more of the primary threats are causing a problem[2] on a distribution system. The nature and location of the problems should lead the operator in the direction to follow in determining threats to the system. Table 4.1 further breaks down the threats into subcategories.

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[2] *Problem is what happens when a threat is realized. Examples may include the following.*
(a) Leak clusters, especially with a common cause or on a common material or component type.
(b) Previously identified hazardous (e.g., Grade 1) leak history or trend.
(c) Damage clusters due to a common cause.
(d) Areas where poor records result in frequent mis-marking.
(e) Known "frequent offender" excavators.
(f) Conditions related to current or past remedial activities.

6 IDENTIFY AND IMPLEMENT MEASURES TO ADDRESS RISKS

Risk management measures are techniques or practices consisting of a broad category of activities that includes prevention, remediation, mitigation, and additional or accelerated (A/A) [5] actions. This section provides guide material on A/A actions.

This section offers techniques and actions that have the potential to reduce the risks to a distribution system. There may be other ways to accomplish the same goal. This guidance is not intended to rule out any valid approach an operator uses that leads to safety improvements in the operation of its distribution system. Remember that risk can be managed by eliminating or reducing the likelihood or by lessening the consequences of a potential problem. Section 192.1007(d) requires that these measures include an effective leak management program, unless all leaks are repaired when found.

6.1 General.

(a) Gas distribution systems are made up of various materials and components located in different geographic locations and operated under varying conditions. Accordingly, a risk management technique or practice used by one operator may not have application as a risk management technique or practice to another operator. An operator may have different risk management techniques or practices for different facilities or group of facilities within the same operating environment. If risk management techniques or practices are necessary, the operator may choose those that are appropriate to protect the public for the system being operated.

(b) Risk management techniques and practices vary in that they may address either the likelihood of a problem or the consequence of a problem.

(c) Risk management techniques and practices may address one or more of the identified threats. Operators should rank risks to their system and determine which risk management techniques and practices are most appropriate.

(d) There are a number of ways an operator can address threats and reduce risk to a distribution system. Examples of A/A actions that may be applied as risk management techniques and practices are listed in Table 6.1. An operator may consider these or develop other techniques or practices specific to its system to address the identified risks.

6.2 Leak Management Program.

(a) Leak management is an important risk management technique used by gas distribution operators to maintain the integrity of their distribution systems. Operators consider many factors specific to their geographical location and their specific distribution system to evaluate the severity of the leaks and determine the appropriate actions to mitigate the risk associated with the leaks. The operator may also utilize industry-recognized guidelines or develop and implement an operator-specific, or state-specific, leak management program.

(b) Although some elements of leak management have evolved with improvements in technology and the development of operation and maintenance codes and standards, distribution operators have used the same basic elements since the early days of the industry.

(c) An effective leak management program has the following basic elements.

Locate the leaks in the distribution system;

Evaluate the actual or potential hazards associated with these leaks;

Act appropriately to mitigate these hazards;

Keep records; and

Self-assess to determine if additional actions are necessary to keep people and property safe.

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5 *A/A actions are activities that are performed in addition to the requirements of the Federal Regulations.*

(1) Locate the leaks.

Threats		Examples of Possible A/A Actions
Primary	**Subcategory**	
NATURAL FORCES (e.g., earth movement, lightning, heavy rains/floods, temperature extremes, high winds)	Outside force/weather: Steel pipe	○ Relocate pipe from high risk locations. ○ Replace pipe in high risk locations. ○ Install slip or expansion joints for earth movement. ○ Install strain gages on pipe. ○ Install automatic shut-offs. ○ Expand the use of excess flow valves. ○ Conduct leak survey after significant earthquake or other event.
	Outside force/weather: Plastic pipe	○ Relocate pipe from high risk locations. ○ Replace pipe in high risk locations. ○ Expand the use of excess flow valves. ○ Conduct leak survey after significant earthquake or other event.
	Outside force/weather: Cast iron pipe	○ Replace. ○ Leak survey after an event. ○ Install additional facilities to increase flexibility (e.g., expansion bends, expansion joints).
EXCAVATION DAMAGE	Operator (or its contractor)	○ Conduct enhanced awareness education. ○ Conduct cross bore awareness education. ○ Inspect targeted excavation and backfill activities. > Ensure separation, as needed, from existing facilities and those being installed. > Inspect substructure facilities in vicinity of past and present trenchless excavation activities to determine the presence of cross bores. ○ Inspect for facility support. > Ensure inserted facilities are adequately supported. ○ Improve accuracy of line locating. > Install tracer wire. > Enhance the locating signal by connecting a small anode to the tracer wire. > Install electronic marking devices. ○ Expand the use of excess flow valves. ○ Improve system map accuracy (e.g., updates from field observation or GPS data). ○ Improve system map availability. ○ Install additional line markers.

Table 6.1 Continued

GUIDE MATERIAL APPENDIX G-192-13

(See guide material under §§192.103,192.183, 192.199, 192.203, 192.317, 192.321, 192.327, 192.353, 192.355, 192.361, 192.367, 192.613, 192.614, 192.707, 192.755, 192.917, 192.935, and Guide Material Appendix G-192-6)

CONSIDERATIONS TO MINIMIZE DAMAGE BY OUTSIDE FORCES

1 INTRODUCTION

This Guide Material Appendix is intended as an aid in minimizing the possibility of damage to pipelines by outside force.

2 DESIGN

2.1 Selecting pipe locations.

(a) To provide better control over future construction activities, consideration should be given to installing facilities in private rights-of-way.
(b) When distribution facilities are to be installed in new areas, consideration should be given to developing a plan, in conjunction with other utilities, for assigning a standard location to each utility.
(c) Where practicable, facilities in a street should be installed at a constant distance from the property line. Diagonal installations and installations which "wander" in the street or right-of-way should be avoided. Where the street configuration permits, facilities should be installed in straight lines with right-angle corners at turns. Where practicable, service lines should be installed in a straight line from the main to the meter location.
(d) Where it is economically feasible, parallel main installations on each side of a street should be considered to avoid crossing the street with multiple service lines.
(e) Protective sleeves or bridging should be considered for PE piping in addition to providing adequate backfill and compaction to reduce excessive bending and shear stresses. Protective sleeves are designed to mitigate the stresses imposed on the PE pipe due to earth settlement where other utility crossings are made beneath PE piping. Without bridging or a protective sleeve, earth settlement beneath the existing PE piping may cause a downward bow of the PE piping resulting in stress concentrations at the edges of the excavation area. For protective sleeves, see guide material under §192.367.
(f) The installation of facilities should be avoided in areas where storm sewer lines or catch basins are likely to be installed.
(g) The probable pattern of future land use should be considered in selecting the route for new pipelines.

2.2 Cover.

The cover requirements of §192.327 are minimums. Additional cover should be provided where the potential for damage by outside forces is greater than normal. Consideration should be given to the following.

(a) Agricultural land where deep-plowing equipment or sub-pan breakers are used.
(b) Agricultural land where the grade may be changed to permit irrigation or drainage.
(c) Drainage ditch crossings. Consideration may also be given to alternates, such as casing or a protective concrete or steel slab.
(d) Other utility crossings. The new gas facilities should be installed under the existing facilities, unless adequate cover can be provided or casing, bridging, or other protection is used.
(e) Locations where erosion due to wind, water, or vehicular activity may affect the grade. Riprap, paving, or some other means of protection may be used in lieu of additional cover.
(f) Street locations where future street work is a possibility.
(g) Locations where frost, drought, and heat might affect the pipeline.

(h) Water-body crossings where storm events, scouring, erosion, and dredging may alter the water bottom and change the depth of cover or expose the pipeline.

2.3 Earth Movement.

(a) Identify areas surrounding the pipeline that might be prone to earth movement and could result in excessive strain on the pipeline. Earth movement might include slope instability, landslides, subsidence, frost heave, soil settlement, erosion, or earthquakes.

(b) Consider performing geological studies to determine mitigative measures that might be employed to avoid or minimize negative impact of earth movement on the pipeline. Measures might include ensuring drainage of water from the pipeline trench, ensuring drainage of surface water off the pipeline right-of-way, or stabilizing earth slopes by building retaining walls or installing sheet piling. Consider including installed mitigative measures in as-built drawings.

(c) The following guidelines and references may assist the operator when identifying geological forces which might impose stresses on a pipeline and designing mitigative measures.

(1) INGAA Foundation Report 2015-03, "Mitigation of Land Movement in Steep and Rugged Terrain for Pipeline Projects: Lessons Learned from Constructing Pipelines in West Virginia."

(2) National Oceanic and Atmospheric Administration (NOAA), National Centers for Environmental Information "National Maps" at: www.ncei.noaa.gov/access/monitoring/us-maps.

(3) USGS, "Landslide Hazards" maps and supporting materials at: www.usgs.gov/programs/landslide-hazards/maps.

(4) The Nature Conservancy, "Improving Steep-Slope Pipeline Construction to Reduce Impacts to Natural Resources".

(5) PRCI PR-000-18COMP – R04, "Geohazards Compendium".

2.4 Landfills and unstable soil.

(a) Special consideration should be given when placing pipelines over landfill areas where the supporting fill might decompose. Mitigation measures include extra excavation and soil replacement or additional pipe support, such as slabs or casings.

(b) Long-wall or other mining underneath a pipeline might also lead to pipeline undermining or lack of support. Additional pipeline thickness, support bridging or slabs, or casings are all methods for consideration to mitigate these conditions.

(c) Areas subject to salt mining or sinkholes also deserve special consideration and might warrant one or more of the above solutions.

2.5 Waterways.

(a) Where facilities will be installed in navigable waterways, the following should be considered.

(1) Dynamic interaction between the water and bottom.

(2) Flotation.

(3) Scouring.

(4) Erosion. (e.g., loss of embankment, loss of cover).

(5) Impacts of major storms.

(6) Potential dredging or anchoring activities and establishing a tolerance zone.

(7) Land-based warning signage for ships and boats.

(b) The use of models, such as hydrologic or land mass movement, might be beneficial.

(c) For information regarding protection of structures in navigable waters:

(6) National Research Council report, "Improving the Safety of Marine Pipelines" (1994), available from National Academies Press (NAP) at www.nap.edu/read/2347.

(7) Council for Dredging and Marine Construction Safety (https://cdmcs.org)

(8) Coastal and Marine Operators' Pipeline Industry Initiative (www.camogroup.org)

(9) NTSB Report MAR-21-05 available at www.ntsb.gov/investigations/AccidentReports/Reports/MAR2105.pdf.

3 MARKERS

In addition to the markers required by §192.707, consideration should be given to the following.

3.1 General.

(a) Installing line markers when a main, transmission line, or gathering line crosses or lies in close proximity to an area that, in the operator's judgment, is likely for excavation or damage. Typical examples include the following.
   (1) Drainage areas, such as flood-prone watercourses.
   (2) Irrigation ditches and canals subject to periodic excavations for cleaning out or deepening.
   (3) Drainage ditches subject to periodic grading, including those along roads.
   (4) Agricultural areas in which deep plowing or deep-pan breakers are employed.
   (5) Active drilling or mining areas.
   (6) Waterways or bodies of water subject to dredging or shipping activities.
   (7) Industrial or plant areas where excavating, earth moving, and heavy equipment operating activities are routine.

(b) If multiple pipeline facilities are within the same right-of-way or in the same area, each operator should mark its facilities in a way to eliminate confusion.

(c) When line markers cannot be placed directly over a pipeline due to lack of support, obstructions, or need to facilitate maintenance, the markers can be offset from a pipeline facility. Markers may include language such as “in the vicinity” or “in proximity of,” but should not include specific distances.

3.2 Transmission lines or gathering lines.

(a) Installing markers at designated locations along the right-of-way, where practical, and wherever the party exerting control over the surface use of the land will permit such installations. Possible locations for line marker placement include the following.
   (1) Fence lines.
   (2) Angle points (i.e., bends and changes in pipeline direction).
   (3) Lateral take-off points.
   (4) Stream crossings (including bridges).
   (5) Where necessary to identify pipeline locations for patrols and leak surveys.
   (6) Where necessary for visibility of line markers in both directions.

(b) Using other methods of indicating the presence of the line where the use of conventional markers is not feasible, such as stenciled markers, cast-monument plaques, signs, or devices flush mounted in curbs, sidewalks, streets, building facades, or other appropriate locations.

(c) Installing temporary markers in areas of known heavy construction activity during the period that construction is in progress near existing or newly installed facilities, whether energized or not, particularly along highways, strip mines, and major excavations.

3.3 Distribution lines.

(a) While markers are not normally practical for distribution systems, indicating the presence of the line where special problems exist. See 3.2(b) above for alternate methods of marking.

(b) Installing temporary markers near existing or newly installed facilities, whether energized or not, particularly in areas of construction activity during the period that construction is in progress.

3.4 Underwater pipeline.

The use of buoys, poles, PVC markers, or other forms of temporary marking suitable for underwater pipelines. The type of marker chosen may be influenced by the depth of water, the types of vessels normally navigating the area, and other characteristics of the body of water.

4 MINING ACTIVITIES

(a) An operator should consider the effects of mining activities on pipeline facilities. The ground subsidence and soil overburden can cause significant stresses in pipelines.

(b) Long-wall mining is of special concern to pipeline operators. Long-wall mining involves complete removal of a coal seam, which is typically 200 to 1,500 feet underground. The roof of the mine collapses, and the collapse propagates to the surface.

(c) Operators with pipelines in areas of mining activity should consider the following actions.
 (1) Contact the mine operator to obtain the depth of coal, mined height, width of the seam, location and angle at which the activity passes under the pipeline, estimated schedule of mining activities, and previous subsidence profiles for other mines in the area.
 (2) Review the material properties of the pipe and associated valves and fittings, such as specification, rating or grade, wall thickness, SMYS, toughness, and seam and joint characteristics.
 (3) Perform subsidence calculations to predict the effect on the pipeline. One method of predicting subsidence was developed by the National Coal Board (NCB) and is reported in the "Subsidence Engineers' Handbook."
 (4) Reduce the operating pressure, or remove the pipeline from service, if warranted by predicted stress levels.
 (5) Expose the pipeline to limit overburden stress.
 (6) Monitor subsidence and strain levels. A reference for monitoring subsidence is PRCI L51574, "Non-Conventional Means for Monitoring Pipelines in Areas of Soil Subsidence or Soil Movement."

5 RECORDS

The location of facilities should be accurately mapped or otherwise recorded. The operator should ensure that maps or records used for locating facilities are updated whenever any changes are made.

6 DAMAGE PREVENTION CONSIDERATIONS

See Guide Material Appendix G-192-6 for damage prevention considerations while performing directional drilling or using other trenchless technologies. For damage prevention programs, see guide material under §192.614.

7 VEHICULAR DAMAGE

When determining a safe distance between an aboveground pipeline and vehicular traffic, consideration should be given to relevant factors, including the following.

(a) Type of public road (e.g., residential, federal or state highway, limited access highway).
(b) Type of driveway (e.g., residential, commercial, industrial).
(c) Type of off-road activity (e.g., four-wheeling, snowmobiling).
(d) Speed limit.
(e) Direction of traffic.
(f) Terrain.
(g) Natural or other barriers.
(h) Weather-related road conditions (e.g., ice, snow, snow removal).

8 OTHER

Consideration should be given to the following.

(a) Special precautions to protect buried control lines. See guide material under §192.199.
(b) Installing small-diameter, service line taps off large-diameter pipe so that the top of the tee is lower than the top of the pipe.
(c) The use of colored pipe wrap or coating so that the content of a pipe is readily evident. This coloring should conform to American National Standards where applicable.
(d) Where a plastic pipeline is installed in a common trench with electric underground lines, the need for additional clearance to prevent damage to the gas line from heating or a fault in the power line.
(e) Where future excavation (including grading) is likely, providing suitable means of warning (e.g.,

warning tape, marker paint, flags, temporary markers).

(f) For aboveground facilities, the potential for damage due to vandalism or other causes. Where unusual hazards may reasonably be expected, precaution should be taken to guard against them, such as guards, locks, protective barriers, or even an alternative or underground location.

(g) Responding to requests from third-party designers or planners for information regarding location of buried facilities. Such responses may include the following.
   (1) Providing maps.
   (2) Holding meetings.
   (3) Locating facilities in the field. See 2.7 of the guide material under §192.614.

   Recipients of such information should be reminded that notice of intent to excavate must still be provided in accordance with state or local regulations.

tools or gauge plates to determine if ILI tools will pass through the segment, or run caliper or geometry tools to evaluate bends and other restrictions prior to running the ILI tool. NACE SP0102, Section 4 provides guidance on the following physical and operational characteristics.

(a) Pipeline pressure and temperature.
(b) Launcher and receivers – work space and facility piping.
(c) Insertion devices, such as thermowells and probes.
(d) Pipe diameter and diameter changes.
(e) Wall thickness changes.
(f) Bend radius and back-to-back bends.
(g) Reduced-port and check valves.
(h) Internal coatings.
(i) Sales taps and feeds.
(j) Unbarred tees.
(k) Hydrate precautions.
(l) Pyrophoric precautions.
(m) Product flow and speed.
(n) Pipeline geometry.
(o) Pipeline cleanliness.

5 METHODS OF PROPULSION

Methods and mediums for propelling ILI tools include the following.

(a) Natural gas or other gas.
(b) Air or nitrogen.
(c) Tethered.
(d) Self-propelled.
(e) Liquid medium.

5.1 Natural gas or other gas.

Natural or other gas is typically used to propel ILI tools. The advantage of gas is that the tool can be run without taking the pipeline out of service, depending on the product being transported. Running the tool in gas may not be feasible if the line pressure or flow rates are too low or too high to control speed and gather accurate data.

5.2 Air or nitrogen.

Air or nitrogen can be used to propel ILI tools if the existing gas pressure or flow rates do not permit running ILI tools using gas. The disadvantages of air or nitrogen are that the pipeline must be taken out of service, additional costs might be incurred, and equipment is necessary for pumping and venting.

5.3 Tethered.

Tethered ILI tools are hooked to a cable and mechanically pulled through a pipeline. The advantage of tethered tools is that they do not require extensive launching and receiving facilities. The disadvantages of tethered inspections are that the pipeline generally must be taken out of service and that it is limited to relatively short segments, typically 2 miles or less. The length of pipe that can be inspected in a single pull may be further limited if there are numerous bends in the pipeline.

5.4 Self-propelled.

Self-propelled tools contain a motor used to drive the tool through the pipeline. An advantage of self-propelled tools is that the tool can be used in pipelines where the gas pressure is too low, or the gas flow rate is too slow, to propel standard tools. A disadvantage of self-propelled tools is the selection and available sizes are more limited than for other ILI tools.

10 SAFETY AND ENVIRONMENTAL CONSIDERATIONS

If ILI is used to assess pipe in a covered segment, §192.911(o) requires that operators have procedures to ensure that assessments are conducted in a manner that minimizes environmental and safety risks.

(a) Safety considerations.
  (1) Using qualified personnel.
  (2) Installing tags on valves and listing the sequence of valve operation.
  (3) Ensuring there is a locking device on quick opening closures that provides a warning or prevents opening if the trap is pressurized.
  (4) Determining personal protective equipment that will be needed by those involved with the pigging operations.
(b) Environmental considerations.
  (1) Using appropriate containment methods for expected fluid and debris.
  (2) Recognizing pyrophoric materials and indicating handling methods for such materials. Pyrophoric materials are materials that may spontaneously ignite when exposed to air. An example of a pyrophoric material is black powder composed of iron sulfides.
  (3) Sampling of fluids and solids for compliance with environmental regulations.
  (4) Obtaining permits for hauling and waste disposal.

11 PRE-INSPECTION REQUIREMENTS

Once the ILI tool is on site and ready to be run, several inspection steps should be performed before loading the tool into the launcher. API Std 1163, Section 8.3 provides guidance on the following steps.

(a) Tool-function tests.
(b) Mechanical checks.
(c) Setting up aboveground markers.

12 RUNNING ILI TOOLS

(a) The operator should have procedures for launching and receiving ILI tools and monitoring the ILI progress. The operator may develop procedures or accept the ILI provider's procedures. ILI providers should be consulted for any special instructions on the tools being used. Depending on the size of the ILI tool, cranes or other equipment may be needed to load and unload the ILI tool. Many tools can be pushed into the launcher, but some tools may need to be pulled into the launcher.
(b) If gas is being used to propel the ILI tool, communication with gas control is important. Flow rates and pressures should be monitored and compared with the target range. The movement of the tool should be tracked and compared with the predicted speed.
(c) API Std 1163, Section 8.4 provides some overall guidelines on the following.
  (1) Launching.
  (2) Running.
  (3) Placing aboveground markers.
  (4) Receiving.

13 POST-INSPECTION REQUIREMENTS

Once the ILI tool is removed from the receiver, several inspection steps should be performed. API Std 1163, Section 8.5 provides guidance on the following steps.

(a) Tool-function tests.
(b) Data check.
(c) Direct measurement data (e.g., speed, temperature, magnetism levels for MFL tools).
(d) Data completeness.
(e) Data quality.