BEFORE THE
UNITED STATES DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
WASHINGTON, D.C.

Pipeline Safety: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change and Other Related Amendments	Docket Nos. PHMSA-2016-0136, PHMSA-2011-0023

COMMENTS ON PIPELINE SAFETY: REPAIR CRITERIA, INTEGRITY MANAGEMENT IMPROVEMENTS, CATHODIC PROTECTION, MANAGEMENT OF CHANGE, AND OTHER RELATED AMENDMENTS FINAL RULE

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I. Introduction

The American Gas Association (AGA)[1], American Petroleum Institute (API)[2], American Public Gas Association (APGA)[3] and Interstate Natural Gas Association of America (INGAA)[4] (jointly "the Associations") submit these comments for consideration by the Pipeline and Hazardous Materials Safety Administration (PHMSA) concerning the "Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments" rule ("final rule"). On March 26, 2018, PHMSA announced that this would be the second of two rules[5] addressing the gas transmission pipeline topics raised in the 2016 "Safety of Gas Transmission and Gathering Lines" Notice of Proposed Rulemaking (NPRM)[6], and that this final rule would address important safety topics not included in the 2011 Pipeline Safety Act.[7]

The Associations previously submitted comments to address the first set of topics that PHMSA announced it will include in its first gas transmission rule, the "Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments" rule, which will address the mandates from the 2011 Pipeline Safety Act. Those comments included markups to PHMSA's proposed regulatory text that were intended to mirror the votes and discussions held by the Gas Pipeline Advisory Committee (GPAC) and also identified outstanding concerns. These comments are similar in content and structure. The Associations hope that these comments will assist PHMSA as it drafts a final rule that advances pipeline safety.

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[1] The American Gas Association, founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 73 million residential, commercial and industrial natural gas customers in the U.S., of which 95 percent — over 69 million customers — receive their gas from AGA members. Today, natural gas meets more than one-fourth of the United States' energy needs.

[2] API is the national trade association representing all facets of the oil and natural gas industry, which supports 9.8 million U.S. jobs and 8 percent of the U.S. economy. API's more than 625 members include large integrated companies, as well as exploration and production, refining, marketing, pipeline, and marine businesses, and service and supply firms. They provide most of the nation's energy and are backed by a growing grassroots movement of more than 25 million Americans.

[3] APGA is the national, non-profit association of publicly-owned natural gas distribution systems. APGA was formed in 1961 as a non-profit, non-partisan organization, and currently has over 700 members in 37 states. Overall, there are nearly 1,000 municipally-owned systems in the U.S. serving more than five million customers. Publicly-owned gas systems are not-for-profit retail distribution entities that are owned by, and accountable to, the citizens they serve. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies that have natural gas distribution facilities.

[4] The INGAA is a trade association that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry. INGAA is comprised of 27 members, representing the vast majority of the U.S. interstate natural gas transmission pipeline companies. INGAA's members operate nearly 200,000 miles of pipelines and serve as an indispensable link between natural gas producers and consumers.

[5] *See* "Gas Rule Split-Out" presentation from Mr. Alan Mayberry, Associate Administrator for Pipeline Safety (March 26, 2018). https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=967.

[6] Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 Fed. Reg. 29830 (May 13, 2016).

[7] Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011.

II. General Comments

During the March 26-28, 2018 meeting, the GPAC discussed important issues related to PHMSA's proposed anomaly response remediation requirements for transmission lines. Rather than review the entirety of those discussions, the Associations highlight five key areas that PHMSA should consider based on the March 26-28, 2018 discussion and previous industry comments:

1. Applying "traceable, verifiable and complete" (TVC) requirements to records used in anomaly response calculations is unnecessary and confusing – this requirement was developed for maximum allowable operating pressure (MAOP) records, not for material property records used in anomaly response calculations.

2. PHMSA has adequately addressed tool tolerance/accuracy considerations in its proposed language for integrity assessments.

3. PHMSA should make specific modifications to align the anomaly response criteria with consensus technical standards and current technologies.

4. PHMSA should consider revising § 192.711, § 192.713 and § 192.933 to avoid duplication of the response and remediation criteria.

5. PHMSA should set the effective date of the final rule to be 18 months after publication in the Federal Register.

(1) Applying "traceable, verifiable and complete" (TVC) requirements to records used in anomaly response calculations is unnecessary and confusing – this requirement was developed for MAOP records, not for material property records used in anomaly response calculations.

In the NPRM, PHMSA proposes to require that "pipe and material properties used in remaining strength calculations must be documented in traceable, verifiable, and complete records." The Associations agree that selection of appropriate material data properties is critical to ensuring appropriate calculations to determine whether to respond to an anomaly as an immediate, scheduled or monitored condition. However, the "traceable, verifiable and complete" (TVC) requirement was developed for MAOP records. Reapplying this established standard to anomaly response calculations, which represent a much broader set of pipeline maintenance and integrity management activities, is unnecessary and confusing.

Both the National Transportation Safety Board (NTSB) and PHMSA have previously applied the TVC requirement only when specifically addressing MAOP records. NTSB introduced the TVC concept in recommendations to PG&E following its failure in San Bruno, CA; these recommendations were specific to MAOP reconfirmation.[8] Furthermore, in comments to the NPRM docket, NTSB refers to the need for TVC records only in the context of MAOP records. NTSB states that "PHMSA has determined that

[8] NTSB, Safety Recommendation to Mr. Christopher Johns, President, Pacific Gas and Electric Co., P-10-2, P-10-3 (Jan. 3, 2011), http://www.ntsb.gov/safety/safety-recs/recletters/P-10-002-004.pdf.

additional rules are needed to ensure that [the] records used to establish MAOP are reliable, traceable, verifiable, and complete."[9]

Similarly, PHMSA's two advisory bulletins addressing records reviews only refer to TVC in the context of MAOP records,[10,11] and the records review requirements outlined in Section 23 of the 2011 Act are focused on MAOP.[12] PHMSA fails to offer evidence of any specific problems with the material property records and data operators currently use in anomaly response calculations. Anomaly response calculations represent a much broader set of pipeline maintenance and integrity management activities than MAOP reconfirmation and, as such, operators have amassed a large amount of information that is currently being successfully employed to support anomaly response calculations. PHMSA should not apply the TVC requirement for records used in anomaly response calculations, as this will create confusion regarding which existing records can be used to support the anomaly response calculations that are used to schedule in-field examination and remediation.

As noted by Mr. Mayberry with PHMSA during the March 27, 2018 GPAC discussion, "And we've been down this road together dealing with that phrase, and it's all been within the realm of establishing MAOP."[13] Member Allen concurred: "Yes. I think that makes an awful lot of sense to go ahead and add something in there that says that, you know, these records are related to records that were created or associated with, you know, the pressure.[14]"

(2) PHMSA has adequately addressed tool tolerance consideration in its proposed language for integrity assessments.

The Associations support the GPAC vote that "Operators must consider ILI tool tolerance (account for uncertainty and accuracy) on all runs."[15] PHMSA has already proposed to establish this requirement in numerous locations in its proposed rule language, including: § 192.710(d), § 192.713(d)(3)(iii), § 192.921(a)(1), and § 192.937(c)(1). In addition, the documents listed in § 192.493 and incorporated by reference will also improve understanding of tool tolerances and data interpretation. These proposed requirements cover all scenarios in which inline inspection (ILI) would be used to evaluate anomalies; any additional references to ILI tool tolerance would be redundant and potentially confusing.

For example, § 192.710(d) includes the following requirement: "an operator must explicitly consider uncertainties in reported results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance) in identifying and characterizing anomalies." This detailed

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[9] Letter from Christopher Hart, Chairman, NTSB to U.S. Dep't of Transportation at 6, Docket No. PHMSA 2011- 0023 (June 6, 2016), https://www.regulations.gov/#!documentDetail;D=PHMSA-2011-0023-0148.

[10] Pipeline Safety: Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation, 76 Fed. Reg. 1504 (Jan. 10, 2011).

[11] Pipeline Safety: Verification of Records, 77 Fed. Reg. 26822 (May 7, 2012).

[12] 49 U.S.C. § 60139.

[13] GPAC Meeting Transcript. March 27, 2018. Page 230.

[14] GPAC Meeting Transcript. March 27, 2018. Page 231.

[15] GPAC Meeting Final Voting Slides. March 26-28, 2018. Slide 25.

language reflects the appropriate amount of specificity for the requirement to consider tool tolerance. Exact considerations and processes for addressing tool tolerance may vary by tool and anomaly calculation methodology, based on an operator's overall integrity program.

(3) PHMSA should make specific modifications to align the anomaly response criteria with consensus technical standards and current technologies.

In Section III of these comments, the Associations recommend specific modifications to PHMSA's proposed regulatory text to align the anomaly response criteria with the GPAC's discussion. The Associations offer further detail around the following topics:

A. <u>PHMSA should include a new § 192.714 to describe the engineering critical assessment requirements for dents with indication of metal loss, cracking or a stress riser.</u>

The Associations strongly support PHMSA's proposal to add an engineering critical assessment methodology for dents with indication of metal loss, cracking or a stress riser.[16] As noted by PHMSA, "the original repair criteria for dents were developed in the early 2000s timeframe for both HL and gas integrity management rules. Both ILI technology and analytical techniques to assess dents have advanced significantly since that time. PHMSA has gained confidence in applying ECA techniques to analyze dent defects through recent application of dent ECA in special permits."[17]

The Associations suggest that PHMSA include a new § 192.714 to describe the engineering critical assessment requirements for dents with indication of metal loss, cracking or a stress riser. In Section III of these comments, the Associations recommend language for § 192.714 based on PHMSA's slide presentation during the GPAC meeting and the proceeding discussion and votes. The Associations believe § 192.714 should only apply to dents with indication of metal loss, cracking or a stress riser, as considerations for these dents are different than for plain dents. Engineering analysis requirements for plain dents based on critical strain are already established in Part 192.

B. <u>For crack or crack-like defects, 1.1 times MAOP is an appropriate threshold for "immediate" anomalies.</u>

For crack or crack-like defects, the GPAC directed PHMSA to consider a 1.1 x MAOP threshold for immediate conditions, "after tool tolerance has been field verified and applied."[18] As discussed above, PHMSA's proposed language already includes requirements for explicitly considering and verifying tool tolerance. Using 1.1 x MAOP as the immediate threshold for crack anomalies appropriately balances the need for a conservative criterion with the need to minimize the customer and community disruptions associated with immediate conditions. 1.1 x MAOP is consistent with the existing threshold for immediate corrosion anomalies in § 192.933(d)(1)(i) and API RP 1176: *Recommended Practice for Assessment and Management of Cracking in Pipelines*.

Per Member Drake, "I just want to follow up on one point, and I want to be clear on this. I'm talking about an either/or here with the 1.1 and tool tolerances. I'm not talking about adding tool tolerances,

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[16] GPAC Meeting Final Voting Slides. March 26-28, 2018. Slide 20.
[17] PHMSA. "GPAC-Slide_Presentation_-Gas_Rule_-_March_26_to_28_Mtg_5_-_FINAL." March 26-28, 2018. Slide 147.
[18] GPAC Meeting Final Voting Slides. March 26-28, 2018. Slide 22.

colony considerations, growth modeling, and stay at 1.25. I think what that's going to do is actually dis-incentivize people from running this tool, especially given the developmental nature of the tool. People are not going to take that risk of running that thing and having to jump over this humongous hurdle. So I think you're trying to land here in a place that incentivizes people to do the right thing but not punishing them inordinately for what they find, but keeps this in front of them and manages it appropriately."[19] And, per Member Airey, "Let me follow up on that if I could. What if we just made the change to 1.1? It seems to me that that's a reasonable trigger for immediate action…"[20] Finally, per Member Campbell, "But when you start having a lot of things that you're calling urgent in that urgent category and they turn out not to be…it's very, very disruptive. So if I'm having to get emergency permits and then I'm digging next to a big road or a highway, I've got all kinds of road issues, I have everybody and their brother mad at me because I just impacted their commute, I mean, it's really pretty amazing how quickly that sort of can spin up on you."[21]

C. *For corrosion metal loss anomalies in class 3 and 4 areas, 1.39 times MAOP is an appropriately conservative threshold for "scheduled" anomalies.*

During the March 28, 2018 meeting, the GPAC had an extensive discussion regarding whether the appropriate safety factor for scheduled (one- or two-year) metal loss anomalies in class 3 and 4 areas is 1.39 x MAOP or 1.5 x MAOP. It is critical to note that any metal loss anomalies exceeding the "scheduled" threshold in class 3 and 4 areas, and all metal loss anomalies in class 1 and 2 areas, will still be evaluated and remediated in accordance with ASME B31.8S (2004) Section 7, Figure 4.

The Associations offer the following three examples to demonstrate that 1.39 x MAOP is an appropriately conservative safety margin for scheduled metal loss anomalies in class 3 and 4 areas. For these typical pipeline parameters, the corrosion growth rate needed for a defect to become critical in one or two years would generally require a high corrosion growth rate.

For each scenario, columns A through E are the calculations based on Modified B31G. The table in columns G through K shows the value of critical depths at given lengths at the safety factors of 1.39 and 1.1 x MAOP. Cells shaded pink indicate that the critical depth is more than 80%, and therefore would be an immediate condition. For all other values, the critical depth for class 3 and class 4 are calculated.

In columns N through Q, the corresponding growth rates needed for an indication to grow to critical size are calculated. The cells shaded in blue correspond to immediate conditions, due to the 80% depth criterion. For all the other values in across all three scenarios, the ***lowest*** corrosion growth rate needed for an indication with a predicted burst pressure of 1.39 x MAOP to grow to 1.1 x MAOP in two years would be 10.9 mils per year for a 36-in diameter, .390-in thick, grade X60 pipe segment. For many cases, the growth rate required would be much higher, up to 60.3 mils per year.

The 10.9 mils per year corresponds to the values used to generate ASME B31.8S (2004) Section 7, Figure 4, and still allows for a 1.1 x MAOP safety margin. Furthermore, it has been demonstrated that 22 mils per year x wall thickness provides a conservative critical corrosion rate for a wide range of pipe diameters and transmission operating pressures;[22] 10.9 mils per year exceeds this conservative criterion

[19] GPAC Meeting Transcript. March 28, 2018. Page 78-79.
[20] GPAC Meeting Transcript. March 28, 2018. Page 81-82.
[21] GPAC Meeting Transcript. March 28, 2018. Page 90.
[22] K.G. Leewis, *Estimating a Universal Critical Corrosion Rate for Pipelines*, NACE Risk Management, June 2013.

for .390-in thick pipe. This indicates that 1.39 x MAOP is an appropriately conservative safety margin for scheduled metal loss anomalies in class 3 and 4 areas.

Example 1: 36-in diameter, .390-in thick, grade X60

For each scenario, columns A through E are the calculations based on Modified B31G. The table in columns G through K shows the value of critical depths at given lengths at the safety factors of 1.39 and 1.1 x MAOP. Cells shaded pink indicate that the critical depth is more than 80%, and therefore would be an immediate condition. For all other values, the critical depth for class 3 and class 4 are calculated.

In columns N through Q, the corresponding growth rates needed for an indication to grow to critical size are calculated. The cells shaded in blue correspond to immediate conditions, due to the 80% depth criterion.

A	B	C	D	E	F	G	H	I	J	K	L	N	O	P	Q
							Critical Depth at given length					Growth rate needed from 1.39 to 1.1			
			A0	7.02			Class 3		Class 4			Class 3		Class 4	
Pipe Diameter	36	In	A	5.084394		Safety factor	1.39	1.1	1.39	1.1					
SMYS	60000	Psi	A/A0	0.724273		L/D	903.5	715	650	520		1 Yr	2 Yr	1 Yr	2 Yr
Nominal Wall thickness	0.39	In	MT	3.699112		1	0.378	0.3826	0.3838	0.3856		4.6	2.3	1.8	0.9
			Dt	14.04		2	0.3494	0.3644	0.3682	0.3746		15	7.5	6.4	3.2
Length	18	In	L^2	324		3	0.3174	0.3426	0.3494	0.3608		25.2	12.6	11.4	5.7
Depth	0.282466	In	L^4	104976		4	0.2895	0.3223	0.3314	0.3473		32.8	16.4	15.9	7.95
Depth %	72%		L^2/Dt	23.07692		5	0.2674	0.3053	0.3162	0.3356		37.9	18.95	19.4	9.7
			MT (>50)	4.038462		6	0.2504	0.2916	0.3038	0.3257		41.2	20.6	21.9	10.95
			MT(<=50)	3.699112		7	0.2373	0.2807	0.2938	0.3177		43.4	21.7	23.9	11.95
Pburst	520.0007	Psi				8	0.22718	0.272	0.2857	0.3111		44.82	22.41	25.4	12.7
P-100%SMYS	1300	Psi				9	0.2191	0.2649	0.2792	0.3056		45.8	22.9	26.4	13.2
MAOP Class 3	650	Psi				10	0.2127	0.2592	0.2738	0.3011		46.5	23.25	27.3	13.65
MAOP Class 4	520	Psi				11	0.2074	0.2545	0.2693	0.2974		47.1	23.55	28.1	14.05
1.39 * Class 3	903.5					12	0.2031	0.2505	0.2656	0.2942		47.4	23.7	28.6	14.3
1.39 * Class 4	722.8					18	0.1879	0.2363	0.252	0.2825		48.4	24.2	30.5	15.25
1.1* Class 3	715														
1.1 * Class 4	572														
80%	0.312														

Example 2: 30-in diameter, .500-in thick, grade X52

For each scenario, columns A through E are the calculations based on Modified B31G. The table in columns G through K shows the value of critical depths at given lengths at the safety factors of 1.39 and 1.1 x MAOP. Cells shaded pink indicate that the critical depth is more than 80%, and therefore would be an immediate condition. For all other values, the critical depth for class 3 and class 4 are calculated.

In columns N through Q, the corresponding growth rates needed for an indication to grow to critical size are calculated. The cells shaded in blue correspond to immediate conditions, due to the 80% depth criterion.

A	B	C	D	E	F	G	H	I	J	K	L	N	O	P	Q
							Critical Depth at given length					Growth rate needed from 1.39 to 1.1			
			A0	9			Class 3		Class 4			Class 3		Class 4	
Pipe Diameter	30	In	A	6.3254754		Safety factor	1.39	1.1	1.39	1.1		1.39	1.1	1.39	1.1
SMYS	52000	Psi	A/A0	0.7028306		L/D	1205	953	964	763		1 Yr	2 Yr	1 Yr	2 Yr
Nominal Wall thickness	0.5	In	MT	3.6026879		2	0.4529	0.47	0.4694	0.4792		17.1	8.55	9.8	4.9
			Dt	15		4	0.3803	0.4192	0.4178	0.4418		38.9	19.45	24	12
Length	18	In	L^2	324		6	0.3308	0.3807	0.3789	0.4119		49.9	24.95	33	16.5
Depth	0.3514153	In	L^4	104976		8	0.3006	0.3557	0.3534	0.3914		55.1	27.55	38	19
Depth %	70%		L^2/Dt	21.6		10	0.2817	0.3391	0.3368	0.3775		57.4	28.7	40.7	20.35
			MT (>50)	3.9912		12	0.269	0.3278	0.3253	0.3678		58.8	29.4	42.5	21.25
			MT(<=50)	3.6026879		18	0.2487	0.309	0.3065	0.3514		60.3	30.15	44.9	22.45
Pburst	763	Psi													
P-100%SMYS	1733.3333	Psi													
MAOP Class 3	866.66667	Psi													
MAOP Class 4	693.33333	Psi													
1.39 * Class 3	1204.6667														
1.39 * Class 4	963.73333														
1.1* Class 3	953.33333														
1.1 * Class 4	762.66667														
80%	0.4														

Example 3: 24-in diameter, .500-in thick, grade X45

For each scenario, columns A through E are the calculations based on Modified B31G. The table in columns G through K shows the value of critical depths at given lengths at the safety factors of 1.39 and 1.1 x MAOP. Cells shaded pink indicate that the critical depth is more than 80%, and therefore would be an immediate condition. For all other values, the critical depth for class 3 and class 4 are calculated.

In columns N through Q, the corresponding growth rates needed for an indication to grow to critical size are calculated. The cells shaded in blue correspond to immediate conditions, due to the 80% depth criterion.

A	B	C	D	E	F	G	H	I	J	K	L	N	O	P	Q
							Critical Depth at given length					Growth rate needed from 1.39 to 1.1			
			A0	6			Class 3		Class 4			Class 3		Class 4	
Pipe Diameter	24	In	A	4.398276		Safety factor	1.39	1.1	1.39	1.1		1.39	1.1	1.39	1.1
SMYS	45000	Psi	A/A0	0.733046		L/D	1303	1031	1042	825		1 Yr	2 Yr	1 Yr	2 Yr
Nominal Wall thickness	0.5	In	MT	2.836195		2	0.4467	0.4656	0.4649	0.476		18.9	9.45	11.1	5.55
			Dt	12		4	0.372	0.4121	0.4106	0.436		40.1	20.05	25.4	12.7
Length	12	In	L^2	144		8	0.2978	0.3518	0.3498	0.3877		54	27	37.9	18.95
Depth	0.366523	In	L^4	20736		12	0.2698	0.3269	0.3247	0.3665		57.1	28.55	41.8	20.9
Depth %	73%		L^2/Dt	12		18	0.2521	0.3106	0.3083	0.3522		58.5	29.25	43.9	21.95
			MT (>50)	3.684											
			MT(<=50)	2.836195											
Pburst	825	Psi													
P-100%SMYS	1875	Psi													
MAOP Class 3	937.5	Psi													
MAOP Class 4	750	Psi													
1.39 * Class 3	1303.125														
1.39 * Class 4	1042.5														
1.1* Class 3	1031.25														
1.1 * Class 4	825														
80%	0.4														

Finally, in reviewing internal/external corrosion incidents reported to PHMSA since 2010, the Associations identified that more than 70% of these incidents occurred on segments that had NOT been assessed with ILI for metal loss anomalies. The ASME B31.8S (2004) Section 7, Figure 4 requirements apply primarily to lines that have had ILI. The fact that most corrosion incidents have occurred on pipelines that have not be inspected with an ILI tool indicates that following the current industry practice to remediate corrosion anomalies identified through ILI based on ASME B31.8S (2004) Section 7, Figure 4 is an effective practice.

D. PHMSA should ensure operators can use the reciprocal of the pipe design factor as an alternative to class-based factors for grading anomalies.

Wherever PHMSA applies class location-based safety factors (e.g., 1.39 x MAOP for scheduled metal loss anomalies in class 3 and 4 areas), it is critical that the code language allow for an alternate factor **equal to** "the reciprocal of the design factor of the installed pipe." This will accommodate segments that are being managed in compliance with the alternate MAOP (§ 192.620) and class location change (§ 192.611) regulations. As noted by Mr. Johnson with Energy Transfer during the GPAC meeting, "[I]f you apply the reciprocals of those, strictly as the Class Location Factors to any of these pipes, say, a pipe that was designed with 0.72 design factor that's operating that way in a Class 2 area, if you apply the Class 2 factor to it, the pipe itself will not pass, ***regardless of whether it has a defect in it***."[23] Similarly, as noted by Mr. Nanney with PHMSA, "When you say Class 1 pipe or whether you say Class 2 or 3, that means you've got a design factor based upon that class and that also means that you would have pipe diameter wall thickness grade attributes based upon that. From Class 1 to Class 2, the reason the question was asked and we added the comment in red was because if you have a class change from 1 to 2, you've had a pressure test in the past at a certain amount to be able to do that. And so that design factor would not change if it was a 0.72, which is, 1.39 is the reciprocal 0.72, and they're both interchanged depending upon how you're using them. That pipe wouldn't change. That same wall thickness and grade would be still there, so that's why we clarified that. We thought it was clarified in the notice, and we'll make sure we clarify it."[24]

When developing code language to allow for consideration of pipe design factor, PHMSA must consider that a pipeline without any anomalies may have a predicted failure pressure **equal to** the reciprocal of the design factor of the installed pipe. The Associations have recommended language in Section III below to allow for consideration of pipe design factor when grading anomalies.

E. Metal-loss affecting a longitudinal seam should be removed from the response criteria if the seam was formed by high-frequency electric resistance welding (HF-ERW).

The Associations identified zero incidents related to corrosion or environmental corrosion cracking ("metal loss") affecting the long seam of HF-ERW pipe from 2010 – 2017. It is well-established that HF-ERW pipe is not susceptible to threats like some pre-1970s LF-ERW seam types.[25] Therefore, PHMSA should remove metal-loss affecting a longitudinal seam from the response criteria if the seam was formed by high-frequency electric resistance welding (HF-ERW).

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[23] GPAC Meeting Transcript. March 28, 2018. Page 67-68.
[24] GPAC Meeting Transcript. March 28, 2018. Page 79-80.
[25] E.B. Clark, B.N. Leis, R.J. Eiber, *Integrity Characteristics of Vintage Pipelines*, Battelle Memorial Institute, October 2004, Columbus, Ohio

F. PHMSA should allow the use of a predicted failure pressure threshold for establishing scheduled response thresholds at a crossing of another pipeline, in an area with widespread circumferential corrosion, or in an area that could affect a girth weld.

PHMSA should allow operators to use predicted failure pressure ratios to evaluate scheduled metal loss anomalies at a crossing of another pipeline, in an area with widespread circumferential corrosion, or in an area that could affect a girth weld. PHMSA should require operators to schedule an evaluation of these anomalies where metal loss is greater than 50% of nominal wall, unless predicted failure pressure is greater than 1.39 x MAOP for class 1 locations and 1.50 x MAOP for class 2, 3, and 4 locations. This is similar to PHMSA's proposed requirements for scheduled metal loss anomalies preferentially affecting the long seam and scheduled crack anomalies.

Per Member Drake, "We talk about using depth as a trigger to creating, you know, for…welds and things like that, that if it's 50 percent or more through the wall that we would now have to repair this, you know, within one to two years. I think that this kind of fights engineering logic that we've used for evaluating defects, and I just want to make sure I'm clear on why we're doing that. What we're worried about is depth and length and width and the stress that the pipe is under. I'll give you an example where this creates a problem for me. I have a river crossing right now. It has a 50-plus percent through wall anomaly that is a pit. It's an HDD crossing. There are on other anomalies on this crossing. The FPR this pipeline operates at 33 percent of SMYS. The FPR failure pressure rate is 3. So, it is three times the MAOP. The, you know, this thing isn't going anywhere.…And, it's a pit that's deep but not long or wide. This would require, because it's a river crossing, now I have to go out and replace the river crossing for a pit. I can't believe that's what we're trying to do here. But, that's going to be what happens."[26]

G. Manufacturing related features should only require a response if the segment has not been tested in accordance with Subpart J test levels.

The effectiveness of a pressure test to Subpart J test levels in assessing manufacturing-related features for gas pipelines is well-documented.[27] Therefore, PHMSA should not require a response for manufacturing related features if the segment in question has been tested in accordance with Subpart J test levels.

(4) PHMSA should consider revising § 192.711, § 192.713 and § 192.933 to avoid duplication of the remediation criteria.

PHMSA has proposed to revise both § 192.713 (anomaly response and remediation criteria for pipelines not covered by Subpart O and operating above 40% of SMYS) and § 192.933 (anomaly response and remediation criteria for pipelines covered in Subpart O) with near-identical requirements. To avoid duplication and potential confusion as § 192.713 and § 192.933 are revised with time, PHSMA should consider revising § 192.713 so that it provides a process for anomaly response and remediation that can be referenced for both pipelines covered by Subpart O and for pipelines not covered by Subpart O and operating above 40% of SMYS.

§ 192.711 and § 192.933 can be revised to reference § 192.713 and establish the two differences in the requirements between Subpart O and non-covered pipelines: 1) anomalies meeting the "scheduled

[26] GPAC Meeting Transcript. March 28, 2018. Page 182-183.
[27] Kiefner & Associates, Inc. for the U.S. Department of Transportation. Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines (May 2007).

condition" criteria must be addressed within one year for pipelines covered in Subpart O and within two years for non-covered segments operating above 40% of SMYS, and 2) operators are allowed 180 days after an assessment for discovery of a condition on pipelines covered in Subpart O and PHMSA has proposed to allow 240 days for discovery of a condition on non-covered segments operating above 40% of SMYS.

In Section III below, the Associations recommend specific modifications to PHMSA's proposed regulatory text in § 192.711, § 192.713 and § 192.933 based on PHMSA's proposed structure for these sections (duplication of requirements in § 192.713 and § 192.933). To demonstrate how these sections might be constructed to eliminate this duplication, the Associations have included Section IV.

(5) PHMSA should set the effective date of the final rule to be 18 months after publication in the Federal Register.

The time and resources required to ensure proper implementation and compliance with the final rule will reflect a monumental undertaking and will involve multi-year planning and organizational changes for most operators. The Associations and our members strongly encourage PHMSA to consider setting the effective date for the final rule to be no sooner than 18 months after the publication of the final rule in the Federal Register. This is the minimum time required for operators to effectively implement the final rule.

As discussed during the GPAC meetings, the NPRM is PHMSA's biggest rulemaking since the promulgation of the federal pipeline safety regulations in 1970. In particular, the second set of transmission topics that comprise this final rule will necessitate substantial revisions and additions to operators' standards and procedures for corrosion control, anomaly remediation, and integrity assessments. Most of the requirements in these sections do not have an implementation period; operators will be required to have new processes, practices and procedures in place immediately upon the effective date of the final rule.

Each operator will have many steps to implement requirements and ensure compliance with each aspect of the final rule. These include but are not limited to:

- Updating, or developing new company policies and procedures;
- Identifying, recruiting and onboarding internal and external staffing to support new work activities;
- Ensuring that internal and external resources are adequately trained;
- Ensuring rate-recovery mechanisms are in place to incorporate the changes in work scope;
- Revising work and project planning and ensuring ongoing compliance and safety work are prioritized;
- Ensuring systems are in place for any new records or documentation that are necessary to support these measures; and
- Allowing operators to identify efficiencies or clarify inconsistencies in performing work activities, reporting, etc., and engage with state and/or municipal agencies

As just one example, the fracture mechanics modeling process, an important cornerstone of the final rule, will be a completely new program for many operators. Implementing this comprehensive program may involve many months of planning, development, implementation and evaluation.

III. Changes to Regulatory Text of Proposed Rule: Incorporation of GPAC Votes & Industry Comments

Throughout the five meetings to discuss the transmission rules, the GPAC generally voted on concepts, rather than specific language. Therefore, the Associations provide the following modifications to the regulatory text of the final rule for PHMSA's consideration. The Associations believe the modifications shown in **red** reflect the changes to the proposals from the NPRM that were endorsed by the GPAC during the five meetings. The Associations have also identified additional concerns that were not voted on by the GPAC, shown in **blue**, but were shared during public comment or identified through written comments by the Associations. Text without markup is identical to the language proposed in PHMSA's 2016 "Safety of Gas Transmission and Gathering Pipelines" NPRM.

PART 192 – TRANSPORTATION OF NATURAL ANDOTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

Subpart A – General

§192.3 Definitions.

(*Note: The Associations have only addressed definitions that PHMSA proposes to add or modify and that are relevant to the second transmission final rule.)*

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

Per the March 26-28, 2018 GPAC Voting Slide 13, PHMSA will,

- "revise the definition for 'close interval survey,' 'in-line inspection,' and 'in-line inspection tool' to read as recommended by PHMSA staff during this meeting and as presented in the slides."

Dry gas or dry natural gas means gas ~~with less than 7 pounds of water per million (MM) cubic feet and not subject to excessive upsets allowing electrolytes into the gas stream~~ **above its dew point and without condensed liquids.**

Per March 26-28, 2018 Final GPAC Voting Slide 14, the GPAC approved the revised definition of "Dry gas or dry natural gas" as indicated.

Electrical survey means a series of closely spaced ~~measurements of the potential difference between two reference electrodes to determine~~ **pipe-to-soil readings over pipelines which are**

Per PHMSA Presentation Slide 118 from the March 26-28, 2018 GPAC meeting, regarding the *Electrical survey* definition, "PHMSA: suggests the Committee

- Consider withdrawing the proposed NPRM changes to this definition.
- The proposed changes were minor technical clarifications proposed in conjunction with proposed changes to Appendix D. During the June 2017 meeting, the Committee voted to withdraw the proposed changes to Appendix D; as a result, the revised definition is not needed."

subsequently analyzed to identify locations where a corrosive current is leaving the pipeline. ~~on ineffectively coated or bare pipelines.~~

~~*Significant Seam Cracking* means cracks or crack-like flaws in the longitudinal seam or heat affected zone of a seam weld where the deepest crack is greater than or equal to 10% of wall thickness or the total interacting length of the cracks is equal to or greater than 75% of the critical length of a 50% through-wall flaw that would fail at a failure pressure less than or equal to 110% of SMYS, as determined in accordance with fracture mechanics failure pressure evaluation methods (§§ 192.624(c) and (d)) for the failure mode using conservative Charpy energy values of the crack-related conditions.~~

Per the March 26-28, 2018 GPAC Voting Slide 21, PHMSA will:

• Strike the proposed definitions of *Significant Seam Cracking* and *Significant Stress Corrosion Cracking* in § 192.3.

~~*Significant Stress Corrosion Cracking* means a stress corrosion cracking (SCC) cluster in which the deepest crack, in a series of interacting cracks, is greater than 10% of the wall thickness and the total interacting length of the cracks is equal to or greater than 75% of the critical length of a 50% through-wall flaw that would fail at a stress level of 110% of SMYS.~~

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

(a) This part prescribes standards, or portions thereof, incorporated by reference into this part with the approval of the Director of the Federal Register in 5 U.S.C. 552(a) and 1 CFR part 51. The materials listed in this section have the full force of law. To enforce any edition other than that specified in this section, PHMSA must publish a notice of change in the FEDERAL REGISTER.

(1) *Availability of standards incorporated by reference.* All of the materials incorporated by reference are available for inspection from several sources, including the following:

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

(ii) The National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202-741-6030 or go to the NARA Web site at: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

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

(2) [Reserved]

(b) American Petroleum Institute (API), 1220 L Street NW., Washington, DC 20005, phone: 202-682-8000, *http://api.org/.*

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

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

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

(4) [Reserved]

(5) API Recommended Practice 1162, “Public Awareness Programs for Pipeline Operators,” 1st edition, December 2003, (API RP 1162), IBR approved for §192.616(a), (b), and (c).

(6) API Recommended Practice 1165, “Recommended Practice for Pipeline SCADA Displays,” First edition, January 2007, (API RP 1165), IBR approved for §192.631(c).

(7) API Specification 5L, “Specification for Line Pipe,” 45th edition, effective July 1, 2013, (API Spec 5L), IBR approved for §§192.55(e); 192.112(a), (b), (d), (e); 192.113; and Item I, Appendix B to Part 192.

(8) ANSI/API Specification 6D, “Specification for Pipeline Valves,”23rd edition, effective October 1, 2008, including Errata 1 (June 2008), Errata2 (/November 2008), Errata 3 (February 2009), Errata 4 (April 2010), Errata 5 (November 2010), Errata 6 (August 2011) Addendum 1 (October 2009), Addendum 2 (August 2011), and Addendum 3 (October 2012), (ANSI/API Spec 6D), IBR approved for §192.145(a).

(9) API Standard 1104, “Welding of Pipelines and Related Facilities,” 20th edition, October 2005, including errata/addendum (July 2007) and errata 2 (2008), (API Std 1104), IBR approved for §§192.225(a); 192.227(a); 192.229(c); 192.241(c); and Item II, Appendix B.

(10) API STD 1163-2005, “In-Line Inspection Systems Qualification Standard,” 1st edition, August 2001, (API STD 1163), IBR approved for §192.493.

(c) [No Changes from Current]

(d) [No Changes from Current]

(e) [No Changes from Current]

(f) [No Changes from Current]

(g) NACE International (NACE), 1440 South Creek Drive, Houston, TX 77084: phone: 281-228-6223 or 800-797-6223, Web site: http://www.nace.org/Publications/.

(1) ANSI/NACE SP0502-2010, Standard Practice, “Pipeline External Corrosion Direct Assessment Methodology,” revised June 24, 2010, (NACE SP0502), IBR approved for §§192.923(b); 192.925(b); 192.931(d); 192.935(b) and 192.939(a).

(2) NACE Standard Practice 0102-2010, "Inline Inspection of Pipelines," Revised 2010, (NACE SP0102), IBR approved for §§ 192.150(a) and 192.493.

(3) NACE Standard Practice 0204-2008, "Stress Corrosion Cracking Direct Assessment," Revised 2008, (NACE SP0204), Reaffirmed 2008, IBR approved for §§ 192.923(b)(3) and 192.929.

(4) NACE Standard Practice 0206-2006, "International Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas," (NACE SP0206-2006), IBR approved for §§ 192.923(b)(2); 192.927(b); and192.927(c).

(h) [No Changes from Current]

(i) [No Changes from Current]

(j) [No Changes from Current]

(k) American Society for Nondestructive Testing (ASNT), P.O. Box 28518, 1711 Arlingate Lane, Columbus, OH, 43228, phone (800) 222-2768, https://www.asnt.org/.

(1) ANSI/ANST ILI-PQ-2010, "In-line Inspection Personnel Qualification and Certification," 2010, (ANSI/ANST ILI-PQ-2010), IBR approved for § 192.493.

(2) RESERVED.

~~(l) Battelle Memorial Institute, 505 King Avenue, Columbus, OH, 43201, phone (800) 201-2011, http://www.battelle.org/.~~

~~(1) Battelle's Experience with ERW and Flash Welding Seam Failures: Causes and Implications (Task 1.4), IBR approved for § 192.624(c) and (d).~~

~~(2) Battelle Memorial Institute, "Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams" (Subtask 2.4) , IBR approved for §192.624(c) and (d).~~

~~(3) Battelle Final Report No. 13-021, "Predicting Times to Failures for ERW Seam Defects that Grow by Pressure Cycle Induced Fatigue (Subtask 2.5), IBR approved for §192.624(c) and (d).~~

~~(4) Battelle Memorial Institute, "Final Summary Report and recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures -- Phase 1" (Task 4.5), IBR approved for §192.624(c) and (d).~~

PHMSA should remove the references to the Battelle reports, which PHMSA proposes to include as fracture mechanics modeling methods. While these reports are very helpful technical resources that should be made available on PHMSA’s website, they are not fracture mechanics models in and of themselves. The Associations recommend an appropriate list of fracture mechanics models in § 192.712 below.

§192.9 What requirements apply to gathering lines?

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

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

(c) *Type A lines~~, Area 1 Lines~~.* An operator of a Type A, ~~Area 1~~ regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in §§**192.5(d),** 192.13, **192.67, 192.127,** 192.150, **192.205, 192.227(c), 192.285(e),** 192.319, 192.461(f), 192.465(f)**-(g)**, 192.473(c), 192.478, **192.485(c), 192.493, 192.506, 192.607, 192.613(c), 192.619(e)-(f), 192.624,** 192.710, **192.711, 192.712,** 192.713, **192.714, 192.750** and in subpart O of this part. However, an operator of a Type A, ~~Area 1~~ regulated onshore gathering line in a Class 2 location may demonstrate compliance with subpart N by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks.

(d) **[No Change from Current]**

(e) **[No Change from Current]**

PHMSA has announced that it will address issues pertaining to gas gathering pipelines in a separate GPAC meeting and final rule. Therefore, PHMSA must update § 192.9(c) as part of **each of the two transmission final rules** to indicate that none of the new gas transmission sections in either rule apply to gathering lines. This is critical for clarity, because although PHMSA has stated that many of these new requirements apply only to transmission, the intent of § 192.9(c) is to list all of the transmission requirements that do not apply to Type A gathering lines. If PHMSA intends to apply any of the new gas transmission regulations to type A gathering lines, that should be discussed and addressed as part of the separate gas gathering GPAC meeting(s) and final rule. (*See* “Gas Rule Split-Out” presentation from Mr. Mayberry with PHMSA, March 26, 2018.)

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

(a) **[No Changes from Current]**

(b) **[No Changes from Current]**

(c) **[No Changes from Current]**

(d) Each operator of an onshore gas transmission pipeline must evaluate and mitigate, as necessary, **significant changes to pipeline operations that pose a risk to safety or the environment through a management of change process.** ~~**risks to the public and environment as an integral part of managing pipeline design, construction, operation, maintenance, and integrity, including management of change.**~~ 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, 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: (1) reason for change, (2) authority for approving changes, (3) analysis of implications, (4) acquisition of required work permits, (5) documentation, (6) communication of change to affected parties, (7) time limitations and (8) qualification of staff. **For transmission pipeline segments other than those covered in Subpart O of this part, this management of change process must be implemented within two (2) years of [*the effective date of the rule*]. If operational constraints limit the operator from meeting this deadline, the operator may petition for an extension of up to one year, upon submittal of a notification to the Associate Administrator of the Office of Pipeline Safety in accordance with §192.635 at least 90 days in advance of the deadline. The notification must include an up-to-date plan for completing all actions required by this section, the reason for the requested extension, current status, proposed completion date, and any needed temporary safety measures to mitigate the impact on safety.**

Per the January 12, 2017 GPAC vote, (Slide 16, Bullet #2), PHMSA will "clarify the requirement only covers significant changes that affect safety and environment."

Per the January 12, 2017 GPAC vote, (Slide 16, Bullet #3), PHMSA will "clearly state that distribution and gathering lines are exempt."

Per the January 12, 2017 GPAC vote, (Slide 16, Bullet #1), "for non-IM assets, provide a 2-year phase-in period with notification procedures for justified extensions."

(e) **[Delete proposed §192.13(e)]**

§192.150 Passage of internal inspection devices.

(a) Except as provided in paragraphs (b) and (c) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must be designed and constructed to accommodate the passage of instrumented internal inspection devices, in accordance with ~~the requirements and recommendations in~~ NACE SP0102-2010, Section 7 (incorporated by reference, see §192.7)

(b) [No change from current]

(c) [No change from current]

Per PHMSA March 2, 2018 GPAC voting slide 1, PHMSA will "revise proposed § 192.493 by striking the phrase 'The requirements and recommendations of' from the paragraph." The intent of the GPAC discussion was to apply this approach throughout other code sections where new standards are to be referenced, including § 192.150.

§192.319 Installation of pipe in a ditch.

(a) [No change from current]

(b) [No change from current]

(c) [No change from current]

(d) Promptly after backfill of 1,000 contiguous feet or more of ~~a ditch for~~ a steel onshore transmission line ~~is backfilled~~, but not later than ~~three months~~ six months after placing the pipeline in service, the operator must perform an indirect assessment to ensure integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG). **If an operator elects to use other technology or another process, the operator must notify PHMSA at least 90 days in advance of use in accordance with 192.633.** The operator must remediate ~~repair~~ any coating damage classified as ~~moderate or~~ severe ~~(voltage drop greater than 35% for DCVG or 50 dBµv for ACVG)~~ in accordance with section 4 of NACE SP0502-2010 (incorporated by reference, see § 192.7) within six months of the assessment. **If permits are necessary, remedial action must be completed promptly after receipt of all necessary permits.** Each operator of transmission pipelines must make and retain for the life of the pipeline records documenting the ~~coating~~ indirect assessment findings and ~~repairs~~ remedial actions.

Per June 2017 GPAC Vote (Slide 16, Bullet #2), PHMSA will "modify the applicability of this requirement to segments >1000' to be consistent with 192.461." Since this requirement applies to *segments* greater than 1000', the associations suggest PHMSA reference "contiguous" backfill.

Per June 2017 GPAC Vote (Slide 16, Bullet #3), PHMSA will "lengthen the assessment & remediation timeframe to 6 months after the pipeline is placed in service (192.319) and provide allowance for delayed permitting."

Per June 2017 GPAC Vote (Slide 16, Bullet #4), PHMSA will "provide flexibility for technology unless objected to by PHMSA."

Per June 2017 GPAC Vote (Slide 16, Bullet #1), PHMSA will "raise the repair threshold from 'moderate' to 'severe' indications." NACE SP0502 describes in detail the process by which an operator must evaluate coating damage and how to identify "severe" coating damage. No NACE standard or publication provides numerical voltage drop thresholds for "severe" coating damage.

Also, PHMSA should use the term "remediate" instead of "repair," consistent with a similar requirement in existing 192.620.

Per June 2017 GPAC Vote (Slide 16, Bullet #5), PHMSA will "modify records requirements as follows: '… make and retain for the life of the pipeline records documenting the ~~coating~~ **indirect** assessment findings and ~~repairs~~ **remedial actions**."

§ 192.461 External corrosion control: Protective coating.

(a) [No change from current]
(b) [No change from current]
(c) [No change from current]
(d) [No change from current]
(e) [No change from current]
(f) Promptly, but no later than ~~three months~~ six months after backfill of 1,000 contiguous feet or more of an onshore transmission pipeline ditch following repair or replacement ~~(if the repair or replacement results in 1,000 feet or more of backfill length along the pipeline)~~, conduct surveys to assess any coating damage to ensure integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG). Coating surveys must be conducted, where practical based upon geographical, technical, or safety reasons. If an operator elects to use other technology or another process, the operator must notify PHMSA at least 90 days in advance of use in accordance with 192.633. Remediate any coating damage classified as ~~moderate or~~ severe ~~(voltage drop greater than 35% for DCVG or 50 dBμv for ACVG)~~ in accordance with section 4 of NACE SP0502-2010 (incorporated by reference, see § 192.7) within six months of the assessment. If permits are necessary, remedial action must be completed promptly following receipt of all necessary permits.

Per June 2017 GPAC Vote (Slide 16, Bullet #3), PHMSA will "lengthen the assessment & remediation timeframe to 6 months after the pipeline is placed in service (192.319) and provide allowance for delayed permitting." Additionally, the Associations remind PHMSA of the comments made by Member Drake regarding compliance considerations when there are physical access restrictions (see pp. 54 & 57 of June 6 meeting transcript).

PHMSA should not require coating surveys where the operator demonstrates that they are not practical, similar to §192.465(f), which requires CIS ***where practical*** based upon geographical, technical, or safety reasons. There are many examples of where coating surveys are not safe, practical or technically applicable, including:

- some marsh, river or lake crossings,
- where pipe that is buried so deep (e.g. some horizontal direction drills) that coating condition surveys are not sufficiently sensitive to perform valid surveys
- where overhead high-voltage AC transmission lines can interfere with some types of surveys.

Per June 2017 GPAC Vote (Slide 16, Bullet #4), PHMSA will "provide flexibility for technology unless objected to by PHMSA."

Per June 2017 GPAC Vote (Slide 16, Bullet #1), PHMSA will "raise the repair threshold from 'moderate' to 'severe' indications." NACE SP0502 describes in detail the process by which an operator must evaluate coating damage and how to identify "severe" coating damage. No NACE standard or publication provides numerical voltage drop thresholds for "severe" coating damage.

§ 192.465 External corrosion control: Monitoring

(a) [No change from current]

(b) [No change from current]

(c) [No change from current]

(d) Each operator **of an onshore gas transmission line** must promptly correct any deficiencies indicated by the inspection and testing provided in paragraphs (a), (b) and (c) of this section. **Within 6 months of identifying a deficiency, the operator must develop a** remedial action **procedure and apply for any necessary permits**. **The** ~~must be~~ **operator must complete remedial action within twelve months or as soon as practicable after obtaining necessary permits.** ~~completed promptly, but no later than the next monitoring interval in § 192.465 or within one year, whichever is less.~~

> Per June 2017 GPAC Vote (Slide 22, Bullet #1), PHMSA will "clarify that the new requirements in paragraph 192.465(d) only apply to gas transmission pipelines."

> Per June 2017 GPAC Vote (Slide 22, Bullet #2), PHMSA will "address comments on timeframe to require remedial action plan and apply any necessary permits within 6 months and complete remedial action within 1 calendar year, not to exceed 15 months, or as practicable after obtaining necessary permits."

(e) [No change from current]

> Per June 2017 GPAC Vote (Slide 22, Bullet #3), PHMSA will "address situations where CIS may not be an effective response to require that operators investigate and mitigate any non-systemic or location-specific causes, and that close interval surveys would only be required to address systemic causes." The Associations offer the language below to attempt to capture this point.

(f) For onshore **gas** transmission lines, **unless non-systemic or location-specific causes of low cathodic protection levels are present as described in paragraph (g) of this section,** where any annual test station reading (pipe-to-soil potential measurement) indicates cathodic protection levels below the required levels in Appendix D of this part, the operator must determine the extent of the area with inadequate cathodic protection. Close interval surveys must be conducted in both directions from the test station with a low cathodic protection (CP) reading at a maximum interval ~~minimum~~ of approximately five feet. ~~foot~~ intervals. Close interval surveys must be conducted, where practical based upon geographical, technical, or safety reasons. Close interval surveys required by this part must be completed with the protective current interrupted unless it is impractical to do so for technical or safety reasons. Remediation of areas with insufficient cathodic protection levels or areas where protective current is found to be leaving the pipeline must be performed in accordance with paragraph (d). The operator must confirm restoration of adequate cathodic protection by close interval survey over the entire area.

(g) **Close interval surveys are not required in instances where low potentials are a result of electrical short to an adjacent foreign structure, rectifier malfunction, interruption of power source, or interruption of CP current due to other non-systemic or location-specific causes. If an operator identifies the potential cause of the low CP reading while conducting the close interval surveys, additional survey points may be unnecessary to perform remediation. In these cases, following the remedial measures, operators must perform a close interval survey over the area found to be deficient to confirm restoration of adequate cathodic protection.**

§ 192.473 External corrosion control: Interference currents.

(a) [No change from current]

(b) [No change from current]

(c) For onshore gas transmission pipeline~~s~~ **segments subject to stray currents**, the program required by paragraph (a) must include:

Per June 2017 GPAC Vote (Slide 27, Bullet #1), PHMSA will "clarify that surveys are required for lines subject to stray current."

(1) Interference surveys for pipeline systems to detect the presence and level of any electrical stray current. Interference surveys must be taken on periodic basis including, when there are current flow increases over pipeline segment grounding design, from any co-located pipelines, structures, or high voltage alternating current (HVAC) power lines, including from additional generation, a voltage up rating, additional lines, new or enlarged power substations, new pipelines or other structures;

(2) Analysis of the results of the survey to determine the cause of the interference and whether the level could **cause significant corrosion (defined as 100 amps per meter squared for AC-induced corrosion), or if it impedes the safe operation of a pipeline, or that may cause a condition that would adversely impact the environment or the public;** ~~impact the effectiveness of cathodic protection~~ and

Per June 2017 GPAC Vote (Slide 27, Bullet #3), PHMSA will "clarify that remedial action is required when the interference is at a level that could cause significant corrosion (defined as 100 amps per meter squared), or if it impedes the safe operating pressure of a pipeline, or that may cause a condition that would adversely affect the environment or public."

(3) **Remedial action is required when the interference is at a level that could cause significant corrosion (defined as 100 amps per meter squared for AC-induced corrosion), or if it impedes the safe operation of a pipeline, or that may cause a condition that would adversely impact the environment or the public. Within 6 months after completion of the survey, the operator must develop a remediation procedure and apply for necessary permits. The operator must complete all remediation within twelve months or as soon as practicable after obtaining necessary permits.** ~~**Implementation of remedial actions to protect the pipeline segment from detrimental interference currents promptly but no later than six months after completion of the survey.**~~

Per June 2017 GPAC Vote (Slide 27, Bullet #2), PHMSA will "update the timeframe for remediation to require a remediation procedure and application for necessary permits within 6 months and complete remediation within 12 months, with allowance for delayed permitting."

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

(a) For onshore transmission pipelines that transport corrosive gas, each operator must develop and implement a monitoring and mitigation program to identify potentially corrosive constituents in the gas being transported and mitigate the corrosive effects, including the requirements of §192.477. Potentially corrosive constituents include but are not limited to: carbon dioxide, hydrogen sulfide, sulfur, microbes, and free water, either by itself or in combination. Each operator must evaluate the partial pressure of each corrosive constituent identified, by itself or in combination~~,~~ to evaluate the effect of the corrosive constituents on the internal corrosion of the pipe and implement mitigation measures.

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

(1) At points where gas with potentially corrosive contaminants enters the pipeline, the use of gas-quality monitoring ~~equipment~~ methods to determine the gas stream constituents;

(2) ~~Product sampling, inhibitor injections, in-line cleaning pigging, separators or other technology to mitigate the potentially corrosive gas stream constituents.~~ For those pipeline segments where potentially corrosive contaminants have been identified, technology to mitigate the effects of potentially corrosive gas stream constituents. Such technologies may include product sampling, inhibitor injections, in-line cleaning pigging, separators or other technology to mitigate potentially corrosive effects; and

(3) Evaluation ~~twice each~~ once per calendar year, at intervals not to exceed ~~7 ½~~ 15 months, of gas stream and liquid quality samples and implementation of adjustments and mitigative measures to ensure that potentially corrosive gas stream constituents are effectively monitored and mitigated.

(c) ~~If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked at least twice each calendar year, at~~

Per June 2017 GPAC Vote (Slide 32, Bullet #4), PHMSA will "limit the applicability of paragraph (a) to the transportation of corrosive gas. PHMSA will provide additional guidance based on the GPAC discussion."

Per Member Gosman & Chairman Danner: "PHMSA should add the word 'identified'." (6/6/2017 Transcript. Page 214).

Per June 2017 GPAC Vote (Slide 32, Bullet #1), PHMSA will "modify (b)(1) as follows: 'At points where gas with potentially corrosive contaminants enters the pipeline, the use of gas-quality monitoring methods to determine the gas stream constituents."

Per June 2017 GPAC Vote (Slide 32, Bullet #5), PHMSA will "revise (b)(2) to read 'technology to mitigate the potentially corrosive gas stream constituents. Such technologies may include product sampling and inhibitor injections."

In 192.478(b)(2), PHMSA should consider replacing the term "potentially corrosive gas stream constituents" with "corrosive effects." It is the "corrosive effects" that ultimately need to be mitigated, and this is consistent with proposed 192.478(a).

The Associations also remind PHMSA that certain constituents, such as microbes, would not have partial pressure.

Per June 2017 GPAC Vote (Slide 32, Bullet #2), PHMSA will "change frequency of monitoring and program review from twice per year to once per calendar year, not to exceed 15 months."

Per June 2017 GPAC Vote (Slide 32, Bullet #3), PHMSA will "delete proposed paragraph (c) and refer to 192.477 in 192.478(a)."

~~intervals not exceeding 7 ½.~~

(d) Each operator must review its monitoring and mitigation program at least ~~twice~~ once each calendar year, at intervals not to exceed ~~7 ½~~ 15 months, based on the results of its gas stream sampling and internal corrosion monitoring in (a) and (b) and implement adjustments in its monitoring for and mitigation of the potential for internal corrosion due to the presence of potentially corrosive gas stream constituents.

§192.485 Remedial measures: Transmission lines operating below 40 percent SYMS.

(a) *General corrosion.* Each segment of transmission line operating below 40 percent SYMS and not covered under subpart O–Gas Transmission Pipeline Integrity Management with general corrosion and with a remaining wall thickness less than that required for the MAOP of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) *Localized corrosion pitting.* Each segment of transmission line pipe operating below 40 percent SYMS and not covered under subpart O–Gas Transmission Pipeline Integrity Management with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.

(c) Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G (incorporated by reference, *see* §192.7), ~~or~~ the procedure in PRCI PR 3-805 (R-STRENG) (incorporated by reference, see §192.7) or an alternative equivalent method of remaining strength calculation for corrosion defects. ~~Both~~ These procedures apply to corroded regions that do not

Per PHMSA Presentation Slide 163 from the March 26-28, 2018 GPAC meeting, "The new repair requirements proposed in the NPRM have limited applicability (192.711 & 192.713 only apply to lines ≥ 40% SMYS; and 192.933 only applies to HCA)."

If PHMSA's intent is for § 192.485 to provide corrosion anomaly response and repair requirements for pipelines below 40% of SMYS outside of HCAs, this must be explicitly stated. Otherwise, §192.485 is duplicative with §§192.713 and 192.933 and confusing.

Per the March 26-28, 2018 GPAC Voting Slide 25, "Remove the PFP standards for Class 1 and 2 from the proposed §§ 192.713(d)(3)(iii) and 192.933(d)(2)(iii). For Class 3 and 4, revise the proposed §§ 192.713(d)(3)(iii) and 192.933(d)(2)(iii) to consider a PFP ratio between 1.39 – 1.50 based on the technical discussions of the committee."

Since § 192.485 is for low-stress pipelines, additional class-based factors are unnecessary. If PHMSA chooses to retain class-based factors in § 192.485, it must specify these factors consistent with 192.713 and 192.933 to avoid confusion:

- For Class 1 and 2: 1.1 x MAOP
- For Class 3 and 4: 1.39 x MAOP, or the reciprocal of the design factor of the installed pipe

For pressure reduction procedures, PHMSA should remove references to the 80 percent wall loss limit, as it is duplicative with "subject to the limitations prescribed in the equations procedures."

Per the March 26-28, 2018 GPAC Voting Slide 23, PHMSA will "Revise proposed § 192.485(c) to include reference to §192.712 for evaluating corrosion in proximity to cracks or crack-like defects and for operators to make and retain records."

penetrate the pipe wall~~, over 80 percent of the wall thickness~~ and are subject to the limitations prescribed in the procedures~~, including the appropriate use of class location and pipe longitudinal seam factors in pressure calculations for pipe defects~~. When evaluating corrosion in proximity to ~~determining the predicted failure pressure (PFP) for~~ gouges, scrapes, selective seam weld corrosion, and crack-related defects, appropriate failure criteria must be used and justification of the criteria must be documented consistent with the fracture mechanics modeling process in §192.712. ~~Pipe and material properties used in remaining strength calculations and the pressure calculations made under this paragraph must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607.~~

> See discussion in General Comments regarding removing the TVC requirement for records used to support anomaly response calculations.

(1) If pipe diameter or wall thickness is not known or records are not available, the operator must:

- **(i) Use the same diameter and/or wall thickness values that are the basis for the current MAOP; or**
- **(ii) Verify these properties based upon the material documentation process specified in § 192.607.**

(2) If SMYS or actual material yield is not known or records are not available, the operator must:

- **(i) Use the same material properties that are the basis for the current MAOP;**
- **(ii) Assume grade A pipe (30 ksi); or**
- **(iii) Verify these properties using the material documentation process specified in § 192.607.**

> Per the March 26-28, 2018 GPAC Voting Slide 9, PHMSA will "Modify §§ 192.713(d) and 192.933(d) to require that operators use the following assumed values needed to determine predicted failure pressure (PFP) or pressure reduction when these values are not known or not documented in records:
> – Specified Minimum Yield Strength (SMYS) – Assume Grade A pipe, or determine material properties under § 192.607, or use basis for the current MAOP;
>
> – Pipe diameter and wall thickness – use basis for current MAOP or determine material properties under § 192.607."

§192.493 In-line inspection of pipelines

When conducting in-line inspection of pipelines required by this part, each operator must **conform to** ~~comply with~~ ~~the requirements and recommendations of~~ API STD 1163, *In-line Inspection Systems Qualification Standard;* ANSI/ASNT ILI-PQ-2005, *In-line Inspection Personnel Qualification and Certification;* and NACE SP0102-2010, *In-line Inspection of Pipelines* (incorporated by reference, see § 192.7). Assessments may also be conducted using tethered or remotely controlled tools, not explicitly discussed in NACE SP0102-2010, provided they **conform to** ~~comply with~~ those sections of NACE SP0102-2010 that are applicable.

Per PHMSA March 2, 2018 GPAC voting slide 1, PHMSA will "revise proposed §192.493 by striking the phrase 'The requirements and recommendations of' from the paragraph." The intent of the GPAC discussion was to apply this approach throughout other code sections were new standards are to be referenced.

Generally, technical standards establish expectations for "conformance" with that standard, not "compliance."

§192.506 Transmission Lines: Spike ~~hydrostatic~~ pressure test for existing steel pipe with integrity threats

The Associations have previously submitted recommended revisions for § 192.506 and recommended that it be included in the transmission mandates rule (the first gas transmission rule). In the event PHMSA decides to include § 192.506 in the second final rule, the recommended revisions are reproduced below. A more detailed discussion of these recommendations is included in the Associations' previous filing on the transmission mandates rule.

(a) Each segment of an existing steel pipeline that is operated at a hoop stress level of 30% of specified minimum yield strength or more and has been found to have time-dependent cracking, including stress corrosion cracking, must be strength tested by a spike ~~hydrostatic~~ pressure test unless the operator addresses the integrity threat by other means, such as in-line inspection or direct assessment. ~~cannot be addressed in accordance with this section to substantiate the proposed maximum allowable operating pressure.~~

(b) Operators must select a test medium consistent with 192.503(b)-(c). ~~The spike hydrostatic pressure test must use water as the test medium.~~

(c) The baseline test pressure ~~without the additional~~ to be applied after the spike test ~~pressure~~ is the test pressure specified in §§ 192.619(a)(2), or 192.620(a)(2), ~~or 192.624,~~ whichever applies.

(d) The test must be conducted by maintaining the pressure at or above the baseline test pressure for at least 8 hours, as specified in § 192.505~~(e)~~.

(e) After the test pressure stabilizes at the baseline pressure and within the first two hours of the 8-hour test interval, the ~~hydrostatic~~ pressure must be raised (spiked) to a minimum of the lesser of 1.50 times MAOP or ~~105%~~ 100% SMYS. This spike ~~hydrostatic~~ pressure test must be held for at least ~~30~~ 15 minutes.

(f) ~~If the integrity threat being addressed by the spike test is of a time-dependent nature such as a cracking threat, t~~ The operator must establish an appropriate retest interval and conduct periodic retests at that interval using the same spike test pressure or other assessment that addresses the threat. The appropriate retest interval and periodic tests for the time-dependent cracking threat must be determined in accordance with the methodology in § 192.712 ~~624(d)~~.

(g) Other ~~Alternative~~ Technology or ~~Alternative Technical Evaluation~~ Process - Operators may use other ~~alternative~~ technology or ~~an alternative technical evaluation~~ another process that provides a sound engineering basis for establishing a spike ~~hydrostatic~~ pressure test or equivalent. If an operator elects to use alternative technology or an alternative technical evaluation process, the operator must notify PHMSA at least ~~180~~ 90 days in advance of use in accordance with § 192.633. ~~paragraph §192.624(e) of this section.~~ ~~The operator must submit the alternative technical evaluation to the Associate Administrator of Pipeline Safety with the notification and must obtain a "no objection letter" from the Associate Administrator of Pipeline Safety prior to usage of alternative technology or an alternative technical evaluation process.~~ The notification must include the following details:

(1) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments;
(2) Procedures and processes to conduct tests, examinations, and assessments, perform evaluations, analyze defects and flaws, and remediate defects discovered;
(3) Data requirements including original design, maintenance and operating history, anomaly or flaw characterization;
~~(4) Assessment techniques and acceptance criteria;~~
~~(5) Remediation methods for assessment findings;~~

~~(6) Spike hydrostatic pressure test monitoring and acceptance procedures, if used;~~

~~(7) Procedures for remaining crack growth analysis and pipe segment life analysis for the time interval for additional assessments, as required; and~~

(8) Evidence of a review of all procedures and assessments by a **qualified technical** subject matter expert.~~(s) in both metallurgy and fracture mechanics~~

§192.613 Continuing surveillance.

(a) Each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.

(b) If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved, or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with §192.619 (a) and (b).

(c) Following an extreme weather event such as a hurricane or flood, an earthquake, landslide, a natural disaster, or other similar event that has the likelihood of significant damage to pipeline facilities ~~infrastructure~~, an operator must inspect all potentially affected onshore transmission pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline.

> The Associations recommend that inspection be required where there is likelihood of "significant" damage, as discussed during the first GPAC Meeting. (1/11/17 Transcript. Page 83. Line 8.)

> Per PHMSA Jan. 11-12 GPAC voting slide 15, PHMSA will "change the word 'infrastructure' to 'facilities' per the presentation slides."

> The Associations ask PHMSA to clarify in the preamble of the Final Rule that the requirement to *inspect* pipelines is not a requirement to perform in-line *inspection* on the pipeline.

> Per PHMSA Jan. 11-12 GPAC voting slide 15, PHMSA will:
>
> - "clarify that the timing in 192.613(c) begins after the operator has made a reasonable determination that the area is safe" and
> - "delete 'whichever is sooner' at the end of 192.613(c)(2)."

(1) Inspection method. An operator must consider 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 damage and the need for the additional assessments required under the introductory text of paragraph (c) in this section.

(2) Time period. The inspection required under the introductory text of paragraph (c) of this section must commence within 72 hours after ~~the cessation of the event, defined as~~ the point in time when the affected area can be safely accessed by ~~the~~ personnel and equipment and when the~~,~~ ~~including availability of~~ personnel and equipment~~,~~ required to perform the inspection, as determined under paragraph (c)(1) of this section, are available. ~~whichever is sooner.~~

(3) Remedial action. An operator must take appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained as a result of performing the inspection required under the introductory paragraph (c) in this section. Such actions might include, but are not limited to:

(i) Reducing the operating pressure or shutting down the pipeline;

(ii) Modifying, repairing, or replacing any damaged pipeline facilities;

(iii) Preventing, mitigating, or eliminating any unsafe conditions in the pipeline right-of-way;

(iv) Performing additional patrols, surveys, tests, or inspections;

(v) Implementing emergency response activities with Federal, State, or local personnel; or

(vi) Notifying affected communities of the steps that can be taken to ensure public safety.

§ 192.633 Other Technology or Process Notification

When allowed in this part, if an operator chooses to use other technology or another process, the operator must notify PHMSA, in accordance with § 192.635. The notification must occur at least 90 days in advance of use and the operator must submit a description of the technology or process to the Associate Administrator of Pipeline Safety with the notification. If an operator does not receive an objection letter from PHMSA within 90 days of notifying PHMSA, the operator can proceed with the other technology or process. PHMSA will notify the operator within 90 days of the notification if additional review time is needed.

> Rather than refer to the “notifications” paragraph within other sections, PHMSA should establish a separate “notifications” section in Subpart L for all of Part 192. The Associations propose §§ 192.633 and 192.635. See discussion in General Comments of 5/1/2018 industry comments submitted to PHMSA titled “COMMENTS ON PIPELINE SAFETY: SAFETY OF GAS TRANMISSION PIPELINES, MAOP RECONFIRMATION, EXPANSION OF ASSESSMENT REQUIREMENTS AND OTHER RELATED AMENDMENTS” to the topic of a single notification section.

§ 192.635 How does an operator notify PHMSA?

(a) An operator must submit all notifications required by this part to the Associate Administrator for Pipeline Safety, by:
   (1) Sending the notification to the Office of Pipeline Safety, Pipeline and Hazardous Material Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP-10, 1200 New Jersey Avenue, SE, Washington, DC 20590-0001;
   (2) Sending the notification to the Information Resources Manager by facsimile to (202) 366-7128; or
   (3) Sending the notification to the Information Resources Manager by e-mail to InformationResourcesManager@dot.gov.
   (4) An operator must also send a copy to a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.

Subpart M – Maintenance
§ 192.710 Pipeline assessments.

The Associations have previously submitted recommended revisions for § 192.710 as part of comments on the transmission mandates rule (the first gas transmission final rule). Because § 192.710 references several of the strengthened assessment methods that PHMSA proposes to include in the second final rule, the Associations have reproduced recommended revisions to § 192.710 below. Recommended revisions that are new to these comments are highlighted in yellow. A more detailed discussion of these recommendations is included in the Associations' previous filing on the transmission mandates rule.

(a) Applicability
  (1) This section applies to onshore transmission pipeline segments that **have a maximum allowable operating pressure that produces a hoop stress greater than or equal to 30 percent of specific minimum yield strength and** are located in:
    (i) A class 3 or class 4 location; or
    (ii) A moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of **free-swimming, commercially available** instrumented in-line inspection tools (i.e. smart pigs) **that can travel (using flow and pressure conditions encountered in normal operations) the length of the pipeline segment, inspect the entire circumference of the pipe, capture and record or transmit relevant, interpretable inspection data in sufficient detail for further evaluation of anomalies without permanent modifications to the pipe segment**."
  (2) This section does not apply to a pipeline segment located in a High Consequence Area as defined in § 192.903.
(b) *General*.
  (1) An operator must perform initial assessments in accordance with this section no later than ***[insert date that is ~~15~~ 14 years after the effective date of the rule]***, **or no later than 10 years after the segment first meets the conditions of § 192.710(a), whichever is later.** ~~and~~
  (2) **An operator must perform** periodic reassessments every ~~20~~ **10** years ~~thereafter~~ **after initial assessment of a pipeline segment**, or **at** a shorter reassessment interval based upon the type **of** anomaly, operational, material, and environmental conditions found on the pipeline segment, or as otherwise necessary to ensure public safety.

The Associations recommend PHMSA include language to account for pipe segments that may one day meet the criteria of §192.710(a) after the effective date of the rule. The associations recommend 10 years to perform initial assessments on newly-applicable segments, as this aligns with the reassessment interval and the existing requirement for newly identified HCA segments.

  (3) *Prior assessment.* An operator may use a prior assessment conducted before ***[Insert effective date of the final rule]*** as an initial assessment for the segment if the assessment **met** ~~meets~~ the Subpart O requirements 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)(1) of this section.
  (4) *MAOP verification.* An operator may use an integrity assessment to meet the requirements of this section if the pipeline segment assessment is conducted in accordance with the integrity assessment requirements of § 192.624(c) for establishing MAOP.
(c) *Assessment Method.* The initial assessments and the reassessments required by paragraph (b) 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 tool or tools capable of detecting ~~corrosion, deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (including stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots, and any other~~ threats to which the segment is susceptible, as determined by the operator. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493;

(2) Pressure test conducted in accordance with subpart J of this part~~. The use of pressure testing is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms, manufacturing and related defect threats, including defective pipe and pipe seams, dents and other forms of mechanical damage~~;

(3) "Spike" ~~hydrostatic~~ pressure test in accordance with § 192.506;

(4) Excavation and *in situ* direct examination by means of visual examination and direct measurement and recorded non-destructive examination results ~~and data needed to assess all threats~~, including but not limited to, ultrasonic testing (UT), radiography, and/or magnetic particle inspection (MPI);

(5) Guided Wave Ultrasonic Testing (GWUT) as described in Appendix F;

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. ~~Use of direct assessment is allowed only if the line is not capable of inspection by internal inspection tools and is not practical to assess (due to low operating pressures and flows, lack of inspection technology, and critical delivery areas such as hospitals and nursing homes) using the methods specified in paragraphs (d)(1) through (d)(5) of this section.~~ 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 or 192.929; or

(7) Other technology or technologies that an operator demonstrates can provide an equivalent understanding of the line pipe for each of the threats to which the pipeline is susceptible.

~~(8) For segments with MAOP less than 30% of the SMYS, an operator must assess for the threats of external and internal corrosion, as follows:~~

~~(i) *External corrosion.* An operator must take one of the following actions to address external corrosion on a low stress segment:~~

~~(A) *Cathodically protected pipe.* To address the threat of external corrosion on cathodically protected pipe, an operator must perform an indirect assessment (i.e. indirect examination tool/method such as close interval survey, alternating current voltage gradient, direct current voltage gradient, or equivalent) at least every seven years on the segment. An operator must use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for the segment. This evaluation must consider, at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.~~

~~(B) *Unprotected pipe or cathodically protected pipe where indirect assessments are impractical.* To address the threat of external corrosion on unprotected pipe or cathodically protected pipe where indirect assessments are impractical, an operator must—~~

~~*(1)* Conduct leakage surveys as required by § 192.706 at 4-month intervals; and~~

~~(2) Every 18 months, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.~~

~~(ii) *Internal corrosion.* To address the threat of internal corrosion on a low stress segment, an operator must—~~

~~(A) Conduct a gas analysis for corrosive agents at least twice each calendar year;~~

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

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

(d) *Data analysis*. An operator ~~person qualified by knowledge, training, and experience~~ must analyze the data obtained from an assessment performed under paragraph (b) of this section to determine if a condition could adversely affect the safe operation of the pipeline. In addition, for internal inspection tools, an operator must explicitly consider uncertainties in reported results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance) in identifying and characterizing anomalies.

This list of uncertainty considerations is applicable for ILI, but not other assessment methods, such as pressure testing.

(e) *Discovery of condition*. Discovery of a condition occurs when an operator has adequate information to determine that a condition exists. An operator must promptly, but no later than 240 ~~180~~ days after an assessment, obtain sufficient information about a condition to make the determination required under paragraph (d), unless the operator can demonstrate that that 240 ~~180~~ -days is impracticable.

(f) *Remediation*. An operator must comply with the requirements in § 192.711 and § 192.713 or § 192.485, where applicable, if a condition that could adversely affect the safe operation of a pipeline is discovered.

(g) *Consideration of information*. An operator must consider all available, relevant information about a pipeline in complying with the requirements in paragraphs (a) through (f).

§192.711 Transmission lines: General requirements for repair procedures.[28]

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

(1) A leak, imperfection, or damage that **requires an immediate response under § 192.713(d)(1)** ~~**impairs its serviceability**~~ is found in a segment of steel transmission line operating at or above 40 percent of the SMYS~~;~~ and it is not feasible to make a permanent repair at the time of discovery~~.~~**; or**

> The Associations caution PHMSA regarding the words "repair" and "remediate." In some instances, measures other than "repairs" (e.g., pressure reductions) are permitted. In other instances, an in-field examination is required to address an ILI assessment indication, but repair/remediation will only be required if the in-field examination verifies the condition. Using "repair" or "remediate" in these instances could create confusion as the code is interpreted over time.

(2) **A leak, imperfection, or damage that requires a scheduled response under § 192.713(d)(3) is found in a segment of steel transmission line operating at or above 40 percent of the SMYS~~;~~ and it is not feasible to make a permanent repair within the required timeframe.**

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

> Per the March 26-28, 2018 GPAC Voting Slide 17, PHMSA will "Clarify in § 192.711(a) that pressure reductions would be required for immediate conditions and in cases where repair schedules cannot be met" and "Refer to § 192.713 for repairs and pressure reductions to avoid duplication in these sections."

(1) ~~Non-**integrity management repairs:**~~ **For assessments completed after [*the effective date of the rule*],** whenever an operator discovers a~~**ny**~~ condition **on** ~~**that could adversely affect the safe operation of**~~ a **segment of steel transmission line operating at or above 40 percent of the SMYS** ~~**pipeline**~~ **and** not covered under subpart O–Gas Transmission Pipeline Integrity Management, it must **address** ~~**correct**~~ the condition as prescribed in § 192.713**(d).** ~~**However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator must reduce the operating pressure to a level not exceeding 80% of the operating pressure at the time the condition was discovered and take additional immediate temporary measures in accordance with**~~

> Per the March 26-28, 2018 GPAC Voting Slide 17, PHMSA will "Add an effective date to § 192.711(b)(1) to clarify that § 192.713 is not retroactive."

> Per PHMSA March 2 GPAC meeting slide 86: "To avoid duplication, refer to 192.713(d)(2) to determine the amount of the pressure reductions." By referring to the entirety of § 192.713(d) in § 192.711(b)(1), this issue is addressed.

[28] To avoid duplication and potential confusion as § 192.713 and § 192.933 are revised over time, PHSMA should consider revising § 192.713 so that it a process for anomaly remediation that can be referenced for both pipelines covered by Subpart O and for pipelines not covered by Subpart O that operate above 40% of SMYS. The Associations demonstrate how this could be accomplished in Section IV below.

~~paragraph (a) to protect persons or property. The operator must make permanent repairs as soon as feasible.~~

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

§ 192.712 Fracture mechanics modeling for failure stress and crack growth analysis

> The Associations have previously submitted recommended revisions for § 192.712 as part of comments on the transmission mandates rule (the first gas transmission rule). Because § 192.713 references the fracture mechanics modeling process outlined in § 192.712, the Associations have reproduced recommended language for § 192.712 below. A more detailed discussion of these recommendations is included in the Associations' previous filing on the transmission mandates rule.

(a) ***Applicability***. **Operators must use the process described in this section where fracture mechanics modeling is required by this part.**

(b) ***Fracture Mechanics Modeling for Failure Stress Pressure.*** **Failure stress pressure must be determined using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both) and boundary condition used (pressure test, ILI, or other). Examples of technically proven models include but are not limited to: for the brittle failure mode, the Raju/Newman Model; for the ductile failure mode, Modified LnSec, API RP 579-1/ASME FFS-1, June 15, 2007, (API 579-1, Second-Edition) – Level II or Level III, CorLas™, and PAFFC (incorporated by reference, *see* § 192.7). The analysis must account for model inaccuracies and tolerances and use conservative assumptions for crack dimensions (length and depth) and failure mode (ductile, brittle, or both) for the microstructure, location, and type of defect.**

- **(1) If pipe diameter or wall thickness is not known or records are not available, the operator must:**
  - **(i) Use the same diameter and/or wall thickness values that are the basis for the current MAOP; or**
  - **(ii) Verify these properties based upon the material documentation process specified in § 192.607.**
- **(2) If actual material toughness is not known or records are not available, the operator must:**
  - **(i) Use Charpy energy values from similar vintage pipe until properties are obtained through opportunistic testing;**
  - **(ii) Verify Charpy energy values based upon the material documentation process specified in § 192.607;**
  - **(iii) Use conservative Charpy energy values of 13.0 ft-lb for pipe body and 4.0 ft-lb for pipe seams. If pipe segment has a history of leaks or failures due to cracks, use default Charpy energy values of 5 ft-lb for pipe body and 1 ft-lb for pipe seam; or**
  - **(iv) Use other appropriate values based on technology or technical publications that an operator demonstrates can provide conservative Charpy energy values of the crack-related conditions of the line pipe, with notification to PHMSA in accordance with § 192.633.**
- **(3) If SMYS or actual material yield is not known or records are not available, the operator must:**
  - **(i) Use the same material properties that are the basis for the current MAOP;**
  - **(ii) Assume grade A pipe (30 ksi); or**
  - **(iii) Verify these properties using the material documentation process specified in § 192.607.**

(c) ***Analysis for Flaw Growth and Remaining Life.*** **If the operator determines that the pipeline segment is susceptible to cyclic fatigue or other loading conditions that could lead to fatigue crack growth, fatigue analysis must be performed using an applicable fatigue crack growth law (for example, Paris Law) or other technically appropriate engineering methodology. For other degradation processes that can cause crack growth, such as stress corrosion cracking, an** appropriate engineering analysis methodology must be used. The above methodologies should account for model inaccuracies and tolerances and be validated by a subject matter expert to determine conservative predictions of flaw growth and remaining life at the maximum allowable operating pressure.

(1) Initial and final flaw size must be determined using a fracture mechanics model appropriate to the failure mode (ductile, brittle or both) and boundary condition used (pressure test, ILI, or other).

(2) For cases dealing with an estimation of the defect sizes that would survive a hydro test pressure, if actual material toughness is not known or records are not available, the operator must:

(i) Use Charpy energy values from similar vintage pipe until properties are obtained through opportunistic testing;

(ii) Verify Charpy energy values based upon the material documentation process specified in § 192.607;

(iii) Use a full size equivalent Charpy upper-shelf energy level of 120 ft-lb; or

(iv) Use other appropriate values based on technology or technical publications that an operator demonstrates can provide conservative Charpy energy values of the crack-related conditions of the line pipe, with notification to PHMSA in accordance with § 192.633.

(3) For subsequent critical flaw size calculations at MAOP of flaws that would survive a hydro test, the same Charpy energy value established in (2) may be used.

(4) The operator must re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated by this analysis has expired. The operator must determine and document if further pressure tests or use of other methods are required at that time. The operator must continue to re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated in the most recent evaluation has expired.

(d) *Review.* Analyses conducted in accordance with this paragraph must be reviewed and confirmed by a subject matter expert.

(e) *Records*. Each operator must keep for the life of the pipeline records of the analyses made in accordance with the requirements of this section after *[insert effective date of the rule].*

§192.713 Transmission lines: Permanent field repair of imperfections and damages.

(a) This section applies to **onshore steel** transmission lines **operating at or above 40 percent of SMYS and not covered under Subpart O-Gas Transmission Pipeline Integrity Management**. Line segments that are located in high consequence areas, as defined in 192.903, must ~~also~~ comply with applicable actions specified by the integrity management requirements in subpart O.

Per the March 26-28, 2018 GPAC Voting Slide 17, PHMSA will "Clarify that § 192.713(a) applies to segments not covered under subpart O (i.e., non-HCAs)."

Per the March 26-28, 2018 GPAC Voting Slide 17, PHMSA will "Clarify § 192.713(c) to replace the phrase "impairs the serviceability" with reference to the repair criteria in § 192.713(d)."

(b) *General*. Each operator must, in repairing **imperfections and damages to** its pipeline systems, ensure that the repairs are made in a safe manner and are made so as to prevent damage to persons, property, or the environment. Operating pressure must be at a safe level during repair operations.

(c) *Repair*. Each imperfection or damage that **is verified by in-field examination and requires remediation under paragraph (d) of this section** ~~impairs the serviceability of~~ ~~pipe in a steel transmission line operating at or above 40 percent of SMYS~~ must be **repaired to support the current maximum allowable operating pressure of the pipeline segment, considering the design factor of the installed pipe. The imperfection or damage must be –**

(1) Removed by cutting out and replacing a cylindrical piece of pipe; ~~or~~

(2) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe**; or**

(3) **Repaired by a repair method defined in ASME B31.8S, Section 7, Table 4.**

For consistency and clarity, the scope should be stated once in (a) and not repeated (i.e., no need to repeat "a steel transmission line operating at or above 40% of SMYS" or "for pipelines not located in high consequence areas…"

Per the March 26-28, 2018 GPAC Voting Slide 24, "In-the-ditch remediation should be based on class location and MAOP." See discussion in General Comments above regarding appropriate use of pipe design factor.

Operators should be allowed to repair pipe using any of the repair methods in ASME B31.8S, which is incorporated by reference.

(d) *Remediation schedule*. ~~For pipelines not located in high consequence areas,~~ An operator must complete the **in-field examination and, if necessary,** remediation of a condition **identified by an assessment completed after [*the effective date of the rule*],** according to the **schedules in this paragraph. Unless a special requirement for responding to certain conditions applies, as provided in this paragraph, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 7, Figure 4. Manufacturing related features meeting the criteria in this paragraph do not require a response if a pressure test has been conducted satisfying the criteria of subpart J to at least 1.25 times the maximum allowable operating pressure. If an operator cannot meet the**

Per the March 26-28, 2018 GPAC Voting Slide 25, PHMSA will "Incorporate § 192.933(c) (i.e., ASME B31.8S, section 7, Figure 4) into § 192.713."

schedule for any condition, the operator must document the reason(s) why it cannot meet the schedule and how the changed schedule will not jeopardize public safety. ~~following schedule:~~

(1) *Immediate ~~repair~~ conditions*. An operator must address ~~repair~~ the following conditions immediately upon discovery:

(i) For metal loss anomalies, a ~~A~~ calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in § 192.7(c). Pipe and material properties used in remaining strength calculations must be documented.~~in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607.~~

(A) If pipe diameter or wall thickness is not known or records are not available, the operator must:

(1) Use the same diameter and/or wall thickness values that are the basis for the current MAOP; or

(2) Verify these properties based upon the material documentation process specified in § 192.607.

(B) If SMYS or actual material yield is not known or records are not available, the operator must:

(1) Use the same material properties that are the basis for the current MAOP;

(2) Assume grade A pipe (30 ksi); or

(3) Verify these properties using the material documentation process specified in § 192.607.

> Per the March 26-28, 2018 GPAC Voting Slide 22, PHMSA will "Consider the below Cracking Repair Criteria for immediate conditions:
> • Crack depth plus corrosion > 50% of pipe wall thickness;
> • Crack depth plus any corrosion is greater than the inspection tool's maximum measurable depth; or
> • The crack anomaly is determined to have ~~(or will have prior to the next assessment)~~ a predicted failure pressure (PFP) that is less than 1.25 x MAOP
> • PHMSA will consider 1.1 x MAOP for immediate conditions after tool tolerance has been field verified and applied. [See discussion in General Comments regarding tool tolerance and 1.1 x MAOP for immediate conditions.]
> • Clarify that material records necessary for evaluating crack defects are determined and documented in accordance with § 192.712."

> PHMSA should consider whether the corrosion depth is actually relevant for the crack depth threshold. The saturation of the crack signal will not be impacted by corrosion metal loss.

(ii) For crack or crack-like anomalies:

(A) Crack depth ~~plus corrosion~~ is greater than 50% of pipe wall thickness, as measured at the crack location; or

(B) ~~Crack depth plus corrosion is greater than the inspection tool's maximum measurable depth; or~~

(B) Fracture mechanics modeling per § 192.712 shows a failure stress pressure at the location of the anomaly less than or equal to 1.1 times the maximum allowable operating pressure.

> The immediate condition requirement of "depth plus corrosion > inspection tool's maximum measurable depth" is not necessary for the electromagnetic acoustic transducer (EMAT) technology commonly used to detect cracks on gas pipelines. This appears to be a criterion due to a known limitation of the ultrasonic crack detection (UTCD) tools resolving crack depths greater than ~4mm. These UTCD tools are more commonly run on hazardous liquid pipelines.

(iii) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) that has ~~any indication of~~ metal loss, cracking or a stress riser, unless an engineering critical assessment of the dent in accordance with § 192.714 demonstrates that critical strain levels are not exceeded.

> Per the March 26-28, 2018 GPAC Voting Slide 23, PHMSA will "Insert the word 'preferentially' to assure that this criterion would not be applied to corrosion pits near a long seam. It would apply to corrosion along the seam that could lead to slotting-type, crack-like defects."

(iv) Metal loss greater than 80% of nominal wall regardless of dimensions.

> Metal loss affecting a HF-ERW seam should be removed from immediate repair. The Associations identified zero incidents related to corrosion or environmental corrosion cracking ("metal loss") incidents affecting HF-ERW pipe from 2010-2017. For DC or LF-ERW, this should be a monitored condition if engineering analysis demonstrate non-injurious metal loss.

(v) ~~An indication of~~ Metal-loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency ~~or high frequency~~ electric resistance welding or by electric flash welding, unless the predicted failure pressure is greater than 1.25 times the maximum allowable operating pressure.

> Per PHMSA March 2 GPAC meeting slide 192: "PHMSA: suggests revising the repair criterion for corrosion metal loss affecting a long seam in HCAs and non-HCAs as follows:
> • Allow (but not require) ECA analysis for the evaluation.
> • If PFP < 1.25 x MAOP the anomaly would be an immediate condition…"

(vi) ~~Any indication of significant stress corrosion cracking (SCC).~~

(vii) ~~Any indication of significant selective seam weld corrosion (SSWC).~~

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

(2) Until the in-field examination and, if necessary, remediation of a condition specified in paragraph (d)(1) is complete, an operator must reduce the operating pressure of the affected pipeline within 5 days of discovery of the condition in accordance with 192.713(d)(5). ~~to the lower of:~~

(ii) ~~A level that restores the safety margin commensurate with the design factor for the Class Location in which the affected pipeline is located, determined using ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991), or AGA Pipeline Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)) ("RSTRENG," incorporated by reference, see § 192.7) for corrosion defects. Both procedures apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations procedures. When determining the predicted failure pressure (PFP) for gouges, scrapes, selective seam weld corrosion, crack-related defects, appropriate failure criteria and justification of the criteria must be used. If SMYS or actual material yield and ultimate tensile strength is not known or not adequately documented by reliable, traceable, verifiable, and complete records, then the operator must assume grade A pipe or determine the material properties based upon the material documentation program specified in § 192.607, or~~

(iii) ~~80% of pressure at the time of discovery, whichever is lower~~.

(3) *Two-year conditions*. An operator must address ~~repair~~ the following conditions within two years of discovery:

Per the March 26-28, 2018 GPAC Voting Slide 21, PHMSA will:
• Strike the proposed definitions of *Significant Seam Cracking* and *Significant Stress Corrosion Cracking* in § 192.3.
• Delete the phrase "any indication of" from the repair criteria related to cracking.

Consistent with ASME B31.8S, operators should be allowed 5 days from discovery of the condition to make the pressure reduction.

Since a pressure reduction could be applied for either an immediate or scheduled condition, the pressure reduction procedure should not be located inside the "immediate response" subsection - the Associations recommend moving this language to sections d(5) and d(6) below.

Per the March 26-28, 2018 GPAC Voting Slide 18, PHMSA will "Revise § 192.713(d)(2) to strike "the lower of…"

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), **unless engineering analyses of the dent demonstrate critical strain levels are not exceeded**.

> Per the March 26-28, 2018 GPAC Voting Slide 20,
>
> - "Allowing (but not require) ECA analysis for the following dent-related repair criteria (HCA and non-HCA):
>   - Dent with indication of metal loss, cracking, or stress riser
>   - Smooth topside dent > 6% diameter (or 0.50 in. deep for D<NPS12)
>   - Dent > 2% diameter (or >0.25 in. deep for D<NPS12) that affects pipe curvature at a girth weld or seam weld

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

> Per the March 26-28, 2018 GPAC Voting Slide 20,
>
> - "Operators must consider ILI tool tolerance (account for uncertainty and accuracy) on all runs.
> - Remove the PFP standards for Class 1 and 2 from the proposed §§ 192.713(d)(3)(iii) and 192.933(d)(2)(iii).
> - For Class 3 and 4, revise the proposed §§ 192.713(d)(3)(iii) and 192.933(d)(2)(iii) to consider a PFP ratio between 1.39 – 1.50 based on the technical discussions of the committee.
>
> See discussion in General Comments around tool tolerances and the importance of considering the original pipe design factor for anomaly response calculations.

(iii) **A dent located between the 4 o'clock position and the 8 o'clock position (bottom ⅓ of the pipe) that has metal loss, cracking or a stress riser, unless an engineering critical assessment of the dent in accordance with § 192.714 demonstrates that critical strain levels are not exceeded.**

(iv) **In Class 3 and 4 locations,** a calculation of the remaining strength of the pipe shows a predicted failure pressure ~~ratio (FPR)~~ at the location of the anomaly less than or equal to **1.39 times the maximum allowable operating pressure, unless the predicted failure pressure is greater than or equal to the maximum allowable operating pressure times the reciprocal of the design factor of the installed pipe.** ~~**1.25 for Class 1 locations, 1.39 for Class 2 locations, 1.67 for Class 3 locations, and 2.00 for Class 4 locations.**~~ This calculation must ~~adequately~~ account for the uncertainty associated with the accuracy of the tool used to perform the assessment.

(v) For crack or crack-like anomalies, fracture mechanics modeling per § 192.712 shows a failure stress pressure at the location of the anomaly less than or equal to 1.39 for class 1 locations or 1.50 for class 2, 3, and 4 locations times the maximum allowable operating pressure, unless the failure stress pressure is greater than or equal to the maximum allowable operating pressure times the reciprocal of the design factor of the installed pipe.

> Per the March 26-28, 2018 GPAC Voting Slide 22, PHMSA will "the below Cracking Repair Criteria for 1-yr (HCA) and 2-yr (non-HCA) conditions:
> • Crack depth plus corrosion > 50% of pipe wall thickness;
> • The crack anomaly is determined to have ~~(or will have prior to the next assessment)~~ a predicted failure pressure (PFP) that is less than 1.39 times MAOP (for class 1 or 2) or 1.50 times MAOP (for other class 2, 3 and 4), ~~or could grow to an immediate condition (1.25 times or less of MAOP) prior to the next assessment.~~
> • Crack anomalies that do not meet either the Immediate or 1-yr/2-yr conditions would be a Monitored Condition."
>
> The Associations believe it is unnecessary and confusing to duplicate the "crack depth plus corrosion >50%" criterion as a scheduled condition, since this is already included as an immediate condition.

(vi) Metal-loss other than an immediate condition preferentially affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency ~~or high frequency~~ electric resistance welding or by electric flash welding, unless:

(A) The predicted failure pressure is greater than 1.39 for class 1 locations and 1.50 for class 2, 3 and 4 locations times the maximum allowable operating pressure; or

(B) The predicted failure pressure is greater than or equal to the maximum allowable operating pressure times the reciprocal of the design factor of the installed pipe.

(vii) ~~An area of corrosion with a predicted metal loss greater than 50% of nominal wall.~~

(viii) ~~Predicted~~ Metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that ~~could~~ is preferentially affecting a girth weld, unless:

(A) The predicted failure pressure is greater than 1.39 for class 1 locations and 1.50 for class 2, 3 and 4 locations times the maximum allowable operating pressure; or

(B) The predicted failure pressure is greater than or equal to the maximum allowable operating pressure times the reciprocal of the design factor of the installed pipe.

> Per PHMSA March 2 GPAC meeting slide 192:
> "PHMSA: suggests revising the repair criterion for corrosion metal loss affecting a long seam in HCAs and non-HCAs as follows:
> • If PFP < 1.39 x MAOP (Class 1) or 1.50 x MAOP (Class 2, 3, & 4), the anomaly would be a 1-yr(HCA)/2-yr (non-HCA) condition.
> • If PFP > 1.39 x MAOP (Class 1) or 1.50 x MAOP (Class 2, 3, & 4), the anomaly would be a monitored condition.

(ix) ~~A gouge or groove greater than 12.5% of nominal wall.~~

(x) ~~Any indication of crack or crack-like defect other than an immediate condition.~~

Per the March 26-28, 2018 GPAC Voting Slide 23, PHMSA will "Delete the following repair criteria (HCAs and non-HCAs):
• Gouge or groove > 12.5% wall thickness
• Area of corrosion > 50%

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

A risk assessment does not monitor conditions – an integrity assessment does.

(i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the pipe).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

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

(iv) A dent that has metal loss, cracking or a stress riser and engineering critical assessment of the dent in accordance with § 192.714 demonstrates that critical strain levels are not exceeded.

(v) A crack or crack-like anomaly for which fracture mechanics modeling per § 192.712 shows a failure stress pressure at the location of the anomaly that is:

(A) Greater than 1.39 for class 1 locations and 1.50 for class 2, 3 and 4 locations times the maximum allowable operating pressure; or

(B) Greater than or equal to the maximum allowable operating pressure times the reciprocal of the design factor of the installed pipe.

Per the March 26-28, 2018 GPAC Voting Slide 23, "PHMSA will evaluate the use of an PFP ratings/thresholds for remediation schedules of anomalies at a crossing of another pipeline in an area with widespread circumferential corrosion or is in an area that could affect a girth weld.

(vi) Metal-loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency ~~or high frequency~~ electric resistance welding or by electric flash welding, where the predicted failure pressure is:

(A) Greater than 1.39 for class 1 locations and 1.50 for class 2, 3 and 4 locations times the maximum allowable operating pressure; or

(B) Greater than or equal to the maximum allowable operating pressure times the reciprocal of the design factor of the installed pipe.

(vii) Metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that is preferentially affecting a girth weld where the predicted failure pressure is:

(A) Greater than 1.39 for class 1 locations and 1.50 for class 2, 3 and 4 locations times the maximum allowable operating pressure; or

(B) Greater than or equal to the maximum allowable operating pressure times the reciprocal of the design factor of the installed pipe.

(5) ***Temporary pressure reduction.*** If an operator is unable to respond within the time limits for conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline segment or take other action that ensures the safety of the pipeline segment. An operator must notify PHMSA in accordance with §192.635 if it cannot meet the response schedule required under paragraph (d) of this section and cannot provide safety through a temporary reduction in operating pressure or other action. Operators must document the calculation method(s) or decisions used to determine reduced operating pressure and the implementation of the actual reduced operating pressure for a period of five years after the pipeline has been examined in the field and, if necessary, repaired and the requirement for reduced operating pressure has been eliminated. For any temporary reduction in operating pressure required by this section, the operator must determine temporary reduction in operating pressure using one of the following methods:

Per the March 26-28, 2018 GPAC Voting Slide 23,

- "When anomalies cannot be repaired in the specified timeframe, clarify that pressure reductions are required comparable to IM requirements (subpart O)."
- Add notification requirements in § 192.713 comparable to IM requirements to require that operators notify PHMSA when:
  - They cannot meet the schedule for evaluation and remediation required under § 192.713 and cannot provide safety through a temporary reduction in operating pressure or through another action, and
  - A temporary pressure reduction exceeds 365 days.

The Associations recommend that PHMSA consider streamlining and clarifying the code by adding a new "Other Technology or Process Notification" section at § 192.633 and a general "How does an operator notify PHMSA?" section at § 192.635.

(i) A level that restores the safety margin commensurate with the pipe design factor for the Class Location in which the affected pipeline is located, determined using ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991), ~~or~~ AGA Pipeline Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)) ("RSTRENG," incorporated by reference, see § 192.7) or an alternative equivalent method of remaining strength calculation for corrosion defects.

It is unnecessary and redundant to restate material property requirements with respect to pressure reductions, as these requirements are already outlined in the specific anomaly remediation criteria, as applicable.

~~Both~~ These procedures ~~apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and~~ are subject to the limitations prescribed in the equations procedures. The pipe design factor shall be determined in accordance with the requirements in either §§ 192.111, 192.611(a)(3), or 192.620. When determining the predicted failure pressure (PFP) for gouges, scrapes, selective seam weld corrosion, crack-related defects, appropriate failure criteria and justification of the criteria must be used~~. If SMYS or actual material yield and ultimate tensile strength is not known or not adequately documented by reliable, traceable, verifiable, and complete records, then the operator must assume grade A pipe or determine the material properties based upon the material documentation program specified in § 192.607;~~

(ii) 80% of pressure at the time of discovery; or ~~whichever is lower~~.

(iii) A level that restores the safety margin to 1.1 times the predicted failure pressure, determined using ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991), AGA Pipeline Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)) ("RSTRENG," incorporated by reference, see § 192.7) or an alternative equivalent method of remaining strength calculation for corrosion defects. These procedures are subject to the limitations prescribed in the equations procedures. When determining the predicted failure pressure for gouges, scrapes, selective seam weld corrosion, crack-related defects, appropriate failure criteria and justification of the criteria must be used.

> Per the March 26-28, 2018 GPAC Voting Slide 18, PHMSA will "Revise § 192.713(d)(2) to strike "the lower of" and allow pressure reduction to be the calculated safe pressure based on class location or 80% of operating pressure or 1.1 times predicted failure pressure (based upon situational safety to public/operating personnel)."

(6) *Long-term pressure reduction.* When a pressure reduction exceeds 365 days, the operator must submit a notification in accordance with §192.635 and explain the reason for the delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline.

(e) *Other conditions*. Unless another timeframe is specified in paragraph (d) of this section, an operator must take appropriate remedial action to correct any condition that could adversely affect the safe operation of a pipeline system in accordance with the criteria, schedules and methods defined in the operator's Operating and Maintenance procedures.

(f) *In situ direct examination of crack defects*. Whenever required to examine an anomaly as required by paragraph (d) of this section ~~by this part~~ , operators must perform direct examination of known locations of cracks or crack-like defects using inverse wave field extrapolation (IWEX), phased array, automated ultrasonic testing (AUT), or equivalent technology that has been validated to detect tight cracks (equal to or less than 0.008 inches crack opening). In-the-ditch examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection and in metallurgy and fracture mechanics for accuracy for the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations.

§192.714 Engineering Critical Assessment for dents with an indication of metal loss or a stress riser

(a) ***Applicability*. Where allowed by this part, if an operator elects to use engineering critical assessment to evaluate a dent anomaly with an indication of metal loss or a stress riser, the operator must use the process described in this section. This process does not apply to dents with coincident cracking, as identified through inline or visual inspection. Dents with coincident cracking must be remediated in accordance with § 192.713 or § 192.933, as applicable.**

(b) ***Engineering Critical Assessment*. An engineering critical assessment is an analytical procedure through which an operator demonstrates that a dent anomaly with an indication of metal loss or a stress riser does not jeopardize pipeline integrity. The engineering critical assessment must:**
   - **(1) Evaluate potential threats to the pipe segment in the vicinity of the dent, including movement, loading and corrosion;**
   - **(2) Identify and quantify all loads acting on the dent;**
   - **(3) Review inline inspection data for damage in the dent area and any associated weld region;**
   - **(4) Perform pipeline curvature-based strain analysis, using inspection data from recent inline inspection with a high resolution deformation tool**
   - **(5) Compare dent profile between recent and previous inline inspections to identify any significant changes in dent depth and shape, if multiple inline inspections with a high resolution deformation tool have been conducted; and**
   - **(6) Evaluate geometric strain level associated with the dent and any associated welds using a technically appropriate methodology ~~using Finite Element Analysis (FEA)~~ and calculate the plastic strain limit damage factors or other technically appropriate damage factors to infer the possibility of a crack. Dents with geometric**

Per PHMSA Presentation Slide 147-149 from the March 26-28, 2018 GPAC meeting:
"PHMSA: Summary of suggested ECA for Denting:
- Evaluate potential threats for the pipe segment in the vicinity of the dent including movement, loading, and cathodic protection;
- Review HR-MFL and HR-Deformation inline inspection data for damage in the dent area and any associated weld region;
- Perform pipeline curvature-based strain analysis using recent HR-Deformation inspection data;
- Compare dent profile between the recent and past HR-Deformation inspections to identify significant changes in dent depth and shape;
- Identify and quantify all loads acting on the dent for a basis for ECA;
- Evaluate strain level associated with dent and any welds using Finite Element Analysis (FEA), and calculate the plastic strain limit damage factors to infer the possibility of a crack;
- Estimate the fatigue life of the dent using FEA with the operational pressure data and different fatigue life prediction models, which must have reassessment safety factor of 2."

Per Mr. Nanney with PHMSA (3/28/18 GPAC Meeting Transcript, page 52): "Just to reply to the comment we got on denting, the answer there would be yes, we agree with the gentleman from TransCanada's comment that Finite Element Analysis would not be required on all dents."

strain levels that exceed 12% or that exceed the critical strain must be remediated in accordance with § 192.713 or § 192.933, as applicable. The analysis must account for material property uncertainties and model inaccuracies and tolerances.

(c) ***Analysis for Remaining Life.*** **If the operator determines that the pipeline segment is susceptible to cyclic fatigue or other loading conditions that could lead to fatigue, fatigue analysis must be performed using a technically appropriate engineering methodology. The analysis must account for model inaccuracies and tolerances. The operator must re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated by this analysis has expired. The operator must determine and document if further pressure tests or use of other methods are required at that time. The operator must continue to re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated in the most recent evaluation has expired.**

(d) ***Review.*** **Analyses conducted in accordance with this section must be reviewed and confirmed by a subject matter expert.**

(e) ***Records*****. Each operator must keep for the life of the pipeline records of the analyses made in accordance with the requirements of this section after** ***[insert effective date of the rule].***

§ 192.750 Launcher and receiver safety.
Any launcher or receiver used after ***[insert 6 months after effective date of rule]***, 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. The operator must use a suitable device to indicate that pressure has been relieved in the barrel or must provide a means to prevent opening of the barrel closure or flange, or prevent insertion or removal of in-line inspection tools, scrapers, or spheres, if pressure has not been relieved.

Subpart O – Gas Transmission Pipeline Integrity Management

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

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

(a) An identification of all high consequence areas, in accordance with §192.905.
(b) A baseline assessment plan meeting the requirements of §192.919 and §192.921.
(c) An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (§192.917) and to evaluate the merits of additional preventive and mitigative measures (§192.935) for each covered segment.
(d) A direct assessment plan, if applicable, meeting the requirements of §192.923, and depending on the threat assessed, of §§192.925, 192.927, or 192.929.
(e) Provisions meeting the requirements of §192.933 for remediating conditions found during an integrity assessment.
(f) A process for continual evaluation and assessment meeting the requirements of §192.937.
(g) If applicable, a plan for confirmatory direct assessment meeting the requirements of §192.931.
(h) Provisions meeting the requirements of §192.935 for adding preventive and mitigative measures to protect the high consequence area.
(i) A performance plan as outlined in ASME/ANSI B31.8S, section 9 that includes performance measures meeting the requirements of §192.945.
(j) Record keeping provisions meeting the requirements of §192.947.
(k) A management of change process as required by §192.13(d).
(l) A quality assurance process as outlined in ASME/ANSI B31.8S, section 12.
(m) A communication plan that includes the elements of ASME/ANSI B31.8S, section 10, and that includes procedures for addressing safety concerns raised by—
    (1) OPS; and
    (2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.
(n) Procedures for providing (when requested), by electronic or other means, a copy of the operator's risk analysis or integrity management program to—
    (1) OPS; and
    (2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.
(o) Procedures for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks.
(p) A process for identification and assessment of newly-identified high consequence areas. (*See* §192.905 and §192.921.)

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

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

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

(2) Static or resident threats, such as manufacturing, welding/fabrication or equipment defects;

(3) Time independent threats such as third party damage/mechanical damage, incorrect operational procedure, weather related and outside force damage; including consideration of seismicity, geology, and soil stability of the area; and

(4) Human error such as operational mishaps and 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~~, verify, validate,~~ and integrate **pertinent** existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. **Operators must begin to integrate pertinent data elements specified in this section starting [*insert date 1 year after effective date of the final rule*], with pertinent attributes integrated by [*insert date 3 years after publication of rule.*]** At a minimum, an operator must gather and evaluate the set of data specified in paragraph (b)(1) of this section and Appendix A to ASME/ANSI B31.8S. The evaluation must analyze both the covered segment and similar non-covered segments, and must:

(1) Integrate **pertinent** information about pipeline attributes and other relevant information, including, but not limited to:

(i) Pipe diameter, wall thickness, grade, seam type and joint factor;

Mr. Nanney stated, "on 917(b) we had heard the committee want us to, in the actual wording, to take out, 'verify' and 'validate', and put in, 'gather' and 'integrate.'" (6/6/2017 Transcript. Page 329. Line 5)

Per the June 7, 2017 GPAC Meeting Vote (Slide 57, Bullet #1, Part 2). PHMSA will add language to require data that is "pertinent" (and that a prudent operator would collect)." The Associations agree that operators should be expected to collect pertinent data in a prudent manner. However, the Associations are concerned that this "prudent operator" standard is undefined, and it would be very complicated to enforce; the Associations do not believe that this term is appropriate for regulatory text. Instead, PHMSA should reference the GPAC's discussion around pertinent data that "a prudent operator would collect" in its preamble to the Final Rule.

Per the June 6-7 GPAC Vote (Slide 57, Bullet #2). PHMSA will include an "implementation timeframe beginning in year 1 with full incorporation by 3 years."

(ii) Manufacturer and manufacturing date, including manufacturing data and records;

(iii) ~~Material properties including, but not limited to, diameter, wall thickness, grade, seam type, hardness, toughness, hard spots, and chemical composition~~;

(iv) Equipment properties;

(v) Year of installation;

(vi) Bending method;

(vii) Joining method, including process and inspection results;

(viii) Depth of cover surveys including ~~stream and~~ river crossings, navigable waterways, and beach approaches;

(ix) Crossings, casings (including if shorted), and locations of foreign line crossings and nearby high voltage power lines;

Per the June 7, 2017 GPAC Meeting Vote (Slide 57, Bullet #1, Part 1), PHMSA will "revise the listing of pipeline attributes in 192.917(b)(1) to be more consistent with existing regulations and B31.8S."

PHMSA should remove proposed §192.917(b)(1)(iii). Diameter, wall thickness, grade, and seam type are already listed in §192.917(b)(1)(i). Hardness, toughness, hard spots, and chemical composition are not listed in ASME B31.8s – 2004.

This Associations believe that calling out "stream crossings" separately is unnecessary and may create confusion. Because streams are smaller bodies of water, the depth of cover information for stream crossings will generally be similar as that for the rest of the pipeline right-of-way; operators will not necessarily identify/define "streams" separately. ASME B31.8S does not call out "streams" separately.

(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 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) ~~Girth weld non-destructive examinations;~~

(A) Post backfill coating surveys;

(B) Coating inspection ("jeeping") reports;

(ii) Cathodic protection installed, including but not limited to type and location;

(iii) Coating type;

(iv) Gas quality;

(v) Flow rate;

(vi) Normal maximum and minimum operating pressures, including maximum allowable operating pressure (MAOP);

(vii) Class location;

(viii) 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;

(ix) Coating condition;

(x) CP system performance;

"Girth weld non-destructive examinations" should be removed to stay consistent with ASME/ANSI B31.8S; girth weld inspection results would already be required by (vii) – joint method.

(xi) Pipe wall temperature;

(xii) 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 assessment, guided wave ultrasonic testing, or other methods;

(B) Close interval survey (CIS) and electrical survey results;

(C) Cathodic protection (CP) rectifier readings;

(D) CP test point survey readings and locations;

(E) AC/DC and foreign structure interference surveys;

(F) Pipe coating surveys, including surveys to detect coating damage, disbonded coatings, or other conditions that compromise the effectiveness of corrosion protection, including but not limited to direct current voltage gradient or alternating current voltage gradient inspections;

(G) Results of examinations of exposed portions of buried pipelines (e.g., pipe and pipe coating condition, see § 192.459), including the results of any non-destructive examinations of the pipe, seam or girth weld, i.e. bell hole inspections;

(H) Stress corrosion cracking (SCC) excavations and findings;

(I) Selective seam weld corrosion (SSWC) excavations and findings;

(J) Gas stream sampling and internal corrosion monitoring results, including cleaning pig sampling results;

(xiii) Outer Diameter/Inner Diameter corrosion monitoring;

(xiv) Operating pressure history and pressure fluctuations, including analysis of effects of pressure cycling and instances of exceeding MAOP by any amount;

(xv) Performance of regulators, relief valves, pressure control devices, or any other device to control or limit operating pressure to less than MAOP;

(xvi) Encroachments ~~and right-of-way activity, including but not limited to, one-call data, pipe exposures resulting from encroachments, and excavation activities due to development or planned development along the pipeline;~~

Mr. Nanney stated "We X'd out in right-of-way activity, we put, encroachments. The one word, that is in the B31.8S." (6/6/2017 Transcript. Page 332. Line 11).

(xvii) Repairs;

(xviii) Vandalism;

(xix) External forces;

(xx) Audits and reviews;

(xxi) Industry experience for incident, leak and failure history;

(xxii) Aerial photography;

(xxiii) Exposure to natural forces in the area of the pipeline, including seismicity, geology, and soil stability of the area; and

(xxiv) ~~Other pertinent information derived from operations and maintenance activities and any additional tests, inspections, surveys, patrols, or monitoring required under this Part.~~

Mr. Nanney stated "…there were some areas where we had added a XXXVI, and we had other pertinent information derived from operations and maintenance. That was some that was not in B31.8S. We did X that out." (6/6/2017 Transcript. Page 332. Line 13).

(2) Use ~~objective, traceable, verified, and~~ validated information and data as inputs, to the maximum extent practicable. Subject matter expert (SME) input may be used. If input is obtained from ~~subject matter experts (~~SMEs~~)~~, the operator must employ adequate control measures to ensure consistency and accuracy of information. ~~adequately correct any bias in SME input. Bias~~ Control measures may include training of SMEs ~~and~~ or use of outside technical experts (independent expert reviews) to assess quality of processes and the judgment of SMEs. ~~Operator must document the names of all SMEs and information submitted by the SMEs for the life of the pipeline.~~

> Mr. Nanney (PHMSA) stated "In number (2) where we had used 'objective, traceable, verified, and validated information'; we just put 'validated information'." (6/6/2017 Transcript. Page 332. Line 18.)

> Per the June 7, 2017 GPAC Meeting Vote (Slide 57, Bullet #3), PHMSA will "address the topic of SME bias… including the elimination of the last sentence the language (or revising the last sentence)."
>
> It is impossible to correct all bias (for example, see comments of Mr. Zamarin on pp. 56-58 of June 7 transcript). Instead, the objective should be: "employ adequate controls measures to ensure consistency and accuracy of information."

(3) Identify and analyze spatial relationships among anomalous information (e.g., corrosion coincident with foreign line crossings; evidence of pipeline damage where overhead imaging shows evidence of encroachment). ~~Storing or recording the information in a common location, including a geographic information system (GIS), alone, is not sufficient~~; and

> Per the June 7, 2017 GPAC Meeting Vote (Slide 57, Bullet #4), PHMSA will "not require a GIS system)."

(4) Analyze the data for interrelationships among pipeline integrity threats, including combinations of applicable risk factors that increase the likelihood of incidents or increase the potential consequences of incidents.

(c) *Risk assessment.* An operator must conduct a risk assessment that follows ASME / ANSI B31.8S, section 5, and analyzes the identified threats and potential consequences of an incident for each covered segment. ~~The risk assessment must include evaluation of the effects of interacting threats, including the potential for interactions of threats and anomalous conditions not previously evaluated.~~ An operator must ensure validity of the methods used to conduct the risk assessment in light of incident, leak, and failure history and other historical information. Validation must ensure the risk assessment methods produce a risk characterization that is consistent with the operator's and industry experience, including evaluations of the cause of past incidents, as determined by root cause analysis or other equivalent means, and include sensitivity analysis of the factors used to characterize both the ~~probability~~ likelihood of loss of pipeline

> Per the June 7, 2017 GPAC Meeting Vote (Slide 63, Bullet #1), PHMSA will "restore reference to B31.8S, Section 5 to clarify other methods besides probabilistic techniques may be used."

> The Associations maintain that the requirement to address interacting threats is adequately addressed in proposed §192.917(c)(2). Therefore, the Associations recommend that PHMSA remove this sentence.

> Per the June 7, 2017 GPAC Meeting Vote (Slide 63, Bullet #2), "in §192.917(c), [PHMSA will] change the term 'probability' to 'likelihood' and delete the term "risk factors" from 192.917 (c)(2)."

integrity and consequences of the postulated loss of pipeline integrity. An operator must use the risk assessment to determine additional preventive and mitigative measures ~~needed~~ (§ 192.935), if needed, for each covered segment, and periodically evaluate the integrity of each covered pipeline segment (§ 192.937(b)).

Beginning [*insert date 3 years after the effective date of the final rule*] the risk assessment must:

(1) Analyze how a potential failure could affect high consequence areas~~, including the consequences of the entire worst-case incident scenario from initial failure to incident termination~~;

(2) Analyze the likelihood of failure due to each individual threat ~~or risk factor~~, and each unique combination of threats ~~or risk factors~~ that interact or simultaneously contribute to risk at a common location;

(3) ~~Lead to better understanding of the nature of the threat, the failure mechanisms, the effectiveness of currently deployed risk mitigation activities, and how to prevent, mitigate, or reduce those risks~~;

(4) Account for, and compensate for, uncertainties in the model and the data used in the risk assessment; and

(5) Evaluate the potential risk reduction associated with candidate risk reduction activities such as preventive and mitigative measures and reduced anomaly remediation and assessment.

Per the July 7, 2017 GPAC Meeting Vote (Slide 63, Bullet #3), PHMSA will "provide a 3-year phase-in period for risk assessments to meet the functional objectives specified in (c)."

The Associations maintain that subject matter experts, including those that have attended PHMSA's Risk Modeling Work Group Meetings, have advised against attempting to model "worst case scenarios." (See Mr. Leewis's comments from the November 30 – December 1, 2016 PHMSA RMWG Meeting. Page 6 of the Meeting Minutes). Section §192.917(c) creates the obligation to consider consequences, including low-likelihood, high-consequence events.

While the Associations agree that risk assessment generally lead to better understanding of risk, including prevention and mitigation, it is inappropriate for the regulation to require ("must") that risk assessment "lead to better understanding. How would "understanding" be documented/enforced? Proposed §192.917(c)(3) should be deleted.

(d) *Plastic transmission pipeline.* An operator of a plastic transmission pipeline must assess the threats to each covered segment using the information in sections 4 and 5 of ASME B31.8S, and consider any threats unique to the integrity of plastic pipe such as poor joint fusion practices, pipe with poor slow crack growth (SCG) resistance, brittle pipe, circumferential cracking, hydrocarbon softening of the pipe, internal and external loads, longitudinal or lateral loads, proximity to elevated heat sources, and point loading.

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

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

line crossing on the covered segment, to define where potential indications of third party damage may exist in the covered segment. An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration.

(2) *Cyclic fatigue.* An operator must evaluate whether cyclic fatigue or other loading conditions (including ground movement, suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, crack, or other defect in the covered segment. The evaluation must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the evaluation together with the criteria used to evaluate the significance of this threat to the covered segment to prioritize the integrity baseline assessment or reassessment. ~~Fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis must be conducted in accordance with § 192.624(d) for cracks.~~ Cyclic fatigue analysis must be validated periodically based on changes ~~performed~~ to pipeline operating or load conditions, not to exceed every seven years. ~~annually, not to exceed 15 months~~.

The Associations encourage PHMSA to reconsider the reference to the Fracture Mechanics requirements in §192.917(e)(2). This section, §192.917, establishes threat evaluation and integrity assessment requirements – fracture mechanics calculations are not needed to evaluate the general threat of cyclic fatigue. For specific, discovered anomalies, evaluation and remediation requirements, including fracture mechanics, are addressed in §192.713/§192.933. In proposed §192.917(e)(2), the cyclic fatigue evaluation requirement is appropriate and sufficient to ensure the threat is appropriately considered in the risk assessment and integrity assessment program.

Per the June 7, 2017 GPAC Vote (Slide 75), PHMSA will "revise §192.917(e)(2) based on GPAC discussion and considering PHMSA's proposed language at the meeting."

Mr. Nanney stated, "what if we all considered confirm the cyclic fatigue analysis is valid periodically based on any changes to cyclic fatigue or other loading conditions not to exceed seven years." (6/7/2017 Transcript. Page 106. Line 17).

The Associations suggest that PHMSA should explicitly cite the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A5.3 for analyzing M&C defects.

(3) *Manufacturing and construction defects.* An operator must analyze the covered segment to determine the risk of failure from manufacturing and construction defects (including seam defects) in the covered segment according to the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A5.3. The analysis must consider the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects only if the covered segment has been subjected to a ~~hydrostatic~~ pressure testing satisfying the criteria of subpart J of at

Per the March 27, 2018 GPAC Vote (Slide 11, Bullet #4), "PHMSA will consider removing the term 'hydrostatic' from (e)(3) and allowing other authorized testing procedures." The Associations maintain that in lieu of a pressure test, PHMSA should allow a pressure reduction or inline inspection methodology to confirm manufacturing and construction threat stability.

least 1.25 times MAOP, or has been subjected to a pressure reduction of 80% of the highest documented operating pressure, or has been assessed by an in-line inspection tool qualified to detect critical manufacturing and construction defects, and the segment has not experienced a reportable in-service incident, as defined in §191.3, attributed to a manufacturing or construction defect since the date of the last subpart J pressure test. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment~~, and must reconfirm or reestablish MAOP in accordance with §192.624(c).~~

(i) The segment has experienced a reportable in-service incident, ~~as described in §192.624(a)(1).~~ as defined in §191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, or a construction-, installation-, or fabrication-related defect.

(ii) MAOP increases, unless a pressure test has been conducted satisfying the criteria of subpart J to at least 1.25 times the new MAOP; or

(iii) The stresses leading to cyclic fatigue increase.

(4) *ERW pipe.* If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW), lap welded pipe, pipe with seam factor less than 1.0 as defined in §192.113, or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or non-covered segment in the pipeline system with such pipe and similar characteristics (including but not limited to similar operating and maintenance histories, coating and material properties and environmental characteristics) has experienced seam failure (including but not

The Associations suggest that PHMSA insert the same qualifying language around prior incidents as presented in the GPAC Vote for §192.917(e)(3)(i) within §192.917(e)(3).

Per the March 27, 2018 GPAC Vote (Slide 11, Bullet #1A), PHMSA will "revise proposed §192.917(e)(3) as follows: in paragraph (e)(3) delete, the phrase '*and must reconfirm or reestablish MAOP in accordance with 192.624(c)*'."

Per the March 27, 2018 GPAC Vote (Slide 11, Bullet #1B), PHMSA will "revise proposed 192.917(e)(3) as follows: in paragraph §192.917(e)(3)(i), delete the reference to §192.624(a)(1) and replace with *'the segment has experienced a reportable in-service incident, as defined in §191.3, since its most recent subpart J pressure test, due to an original manufacturing-related defect, or a construction-, installation-, or fabrication- related defect'*."

If a pressure test has already been conducted to 1.25 times the new MAOP, the manufacturing threat has already been successfully addressed and additional testing is unnecessary.

Operators must be able to consider all relevant pipeline characteristics when determining whether a failure of one ERW seam may indicate likelihood of failure for another ERW seam.

The Associations believe it is critical to apply these requirements to only those pipelines that have experienced failures due to seam cracking and selective seam weld corrosion.

Per the March 27, 2018 GPAC Vote (Slide 11, Bullet #3), "in 192.917(e)(4) [PHMSA will] delete the phrase related to pipe body cracking."

limited to failures due to ~~pipe body cracking,~~ seam cracking and selective seam weld corrosion), or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years (including abnormal operation as defined in §192.605(c)), or MAOP has been increased, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment. ~~Pipe with cracks must be evaluated using fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis to estimate the remaining life of the pipe in accordance with §192.624(c) and (d).~~

> While the Associations agree with PHMSA's proposal to evaluate pipes with cracks using fracture mechanics modeling and cyclic fatigue analysis, including that requirement in this section is duplicative with the anomaly response/repair criteria section (§ 192.933) and could create confusion as regulations are updated in the future. This section, §192.917, establishes integrity assessment requirements – anomaly response, evaluation and remediation is addressed in §192.933.

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

(6) ***Cracks*. If an operator identifies any crack or crack-like defect (including, but not limited to, stress corrosion cracking or other environmentally assisted cracking, ~~unstable seam defects, selective seam weld corrosion~~, girth weld cracks, hook cracks, and fatigue cracks) on a covered pipeline segment that could adversely affect the integrity of the line, the operator must evaluate, and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar characteristics - which may include similar operating and maintenance histories; coating and material properties; and environmental characteristics - associated with the crack or crack-like defect. An operator must establish a schedule for evaluating, and remediating, as necessary, the similar**

> Per the March 27, 2018 GPAC Vote (Slide 12), "In conjunction with striking the previously §192.624(a)(1), add a new §192.917(e)(6) to address cracking within IMP (as proposed by the committee). This would be similar to corrosion in §192.917(e)(5)."
>
> Included in the GPAC proposals was the addition of "operating history and maintenance history" in the characteristics that should be considered when determining whether and where crack remediation is necessary. [March 27, 2017 GPAC Transcript. Page 172-173. Member Drake.]

> "Unstable seam defects" and "selective seam weld corrosion" are not always cracks/crack-like, so the Associations recommend that this example be removed for clarity. For example, certain SSWC anomalies may be more appropriately addressed under (e)(5) than (e)(6); an operator will make this determination based upon the specific characteristics of an anomaly.

segments that is consistent with the operator's established operating and maintenance procedures under part 192 for testing and repair.

§192.921 How is the baseline assessment to be conducted?

The Associations have previously submitted recommended revisions for § 192.921 and recommended that it be included in the transmission mandates rule (the first gas transmission rule). In the event PHMSA decides to include § 192.921 in the second final rule, the recommended revisions are reproduced below. Recommended revisions that are new to these comments are highlighted in yellow. A more detailed discussion of these recommendations is included in the Associations' previous filing on the transmission mandates rule.

(a) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods for each threat to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (*See* §192.917). In addition, an operator may use an integrity assessment to meet the requirements of this section if the pipeline segment assessment is conducted in accordance with the integrity assessment requirements of § 192.624(c) for establishing MAOP.

(1) Internal inspection tool or tools capable of detecting ~~corrosion, deformation and mechanical damage (including dents, gouges and groves), material cracking and crack-like defects (including stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, or any other~~ threats to which the covered segment is susceptible, **as determined by the operator**. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493. ~~A person qualified by knowledge, training, and experience~~ **An operator** must analyze the data obtained from an internal inspection tool to determine if a condition could adversely affect the safe operation of the pipeline. In addition, an operator must explicitly consider uncertainties in reported results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies;

(2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with §192.939; ~~The use of pressure testing is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms, including stress corrosion cracking, manufacturing and related defect threats, including defective pipe and pipe seams, selective seam weld corrosion, dents and other forms of mechanical damage~~

(3) "Spike" ~~hydrostatic~~ pressure test in accordance with § 192.506. The use of spike hydrostatic pressure testing is appropriate for **time-dependent cracking threats, such as stress corrosion cracking;**~~, selective seam weld corrosion, manufacturing and related defects, including defective pipe and pipe seams, and other forms of defect or damage involving cracks or crack-like defects;~~

(4) Excavation and *in situ* direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats, including but not limited to, ultrasonic testing (UT), radiography, and**/or** magnetic particle inspection (MPI);

(5) Guided Wave Ultrasonic Testing (GWUT) conducted as described in Appendix F;

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. **~~Use of direct assessment is allowed only if the line is not capable of inspection by internal inspection tools and is not practical to assess using the methods specified in paragraphs (d)(1) through (d)(5) of this section.~~** An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with, as applicable, the requirements specified in §§192.925, 192.927 or 192.929;

(7) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator choosing this option must notify the Office of Pipeline Safety (OPS) **~~180~~** **90** days before conducting the assessment, in accordance with **§192.633** **~~§192.949~~** **~~and receive a "no objection letter" from the Associate Administrator of Pipeline Safety.~~** **~~An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.~~**

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

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

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

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

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

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

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

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

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

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

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

   (2) Section 192.927, NACE SP0206-2006 if addressing internal corrosion (IC~~DA~~).

   (3) Section 192.929, NACE SP0204-2008 if addressing stress corrosion cracking (SCC~~DA~~).

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

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

a) *Definition.* Internal Corrosion Direct Assessment (ICDA) is a process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO2, O2, hydrogen sulfide or other contaminants present in the gas.

b) *General requirements.* An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in NACE SP0206-2006. The Dry Gas (DG) ICDA process described in this section applies only for a segment of pipe transporting **normally** ~~nominally~~ dry natural gas (see definition §192.3), not for a segment with electrolyte nominally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolyte present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to effectively address internal corrosion, and must notify the Office of Pipeline Safety (OPS) **90** ~~180~~ days before conducting the assessment in accordance with **§ 192.633** ~~§192.921 (a)(4) or §192.937(c)(4).~~

c) *The ICDA plan.* An operator must develop and follow an ICDA plan that **conforms to** ~~meets all the requirements and recommendations in~~ NACE SP0206-2006 and that implements all four steps of the DG-ICDA process including pre-assessment, indirect inspection, detailed examination, and post-assessment. The plan must identify where all ICDA Regions with covered segments are located in the transmission system. An ICDA Region is a continuous length of pipe (including weld joints) uninterrupted by any significant change in water or flow characteristics that includes similar physical characteristics or operating history. An ICDA Region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur until a new input introduces the possibility of water entering the pipeline. In cases where a single covered segment is partially located in two or more ICDA regions, the four-step ICDA process must be completed for each ICDA region in which the covered segment is partially located in order to complete the assessment of the covered segment.

> Per PHMSA March 2, 2018 GPAC voting slide 1, PHMSA will "revise proposed §192.493 by striking the phrase 'The requirements and recommendations of' from the paragraph." The intent of the GPAC discussion was to apply this approach throughout other code sections were new standards are to be referenced.
>
> Generally, technical standards establish expectations for "conformance" with that standard, not "compliance."

(1) *Preassessment*. An operator must **conform to** ~~comply with~~ ~~the requirements and recommendations in~~ NACE SP0206-2006 in conducting the preassessment step of the ICDA process.

(2) *Indirect Inspection.* An operator must **conform to** ~~comply with~~ ~~the requirements and recommendations in~~ NACE SP0206-2006, and the following additional requirements, in conducting the Indirect Inspection step of the ICDA process. Operators must explicitly document the results of its feasibility assessment as required by NACE SP0206-2006, Section 3.3; if any condition that precludes the successful application of ICDA applies, then ICDA may not be used, and another assessment method must be selected. When performing the indirect inspection, the operator must use pipeline specific data, exclusively. The use of assumed pipeline or operational data is prohibited. When calculating the critical inclination angle of liquid holdup and the inclination profile of the pipeline, the operator must consider the accuracy, reliability, and uncertainty of data used to make those calculations, including

but not limited to gas flow velocity (including during upset conditions), pipeline elevation profile survey data (including specific profile at features with inclinations such as road crossing, river crossings, drains, valves, drips, etc.), topographical data, depth of cover, etc. The operator must select locations for direct examination, and establish the extent of pipe exposure needed (i.e., the size of the bell hole), to explicitly account for these uncertainties and their cumulative effect on the precise location of predicted liquid dropout.

(3) *Detailed Examination.* An operator must conform to ~~comply with~~ ~~the requirements and recommendations in~~ NACE SP0206-2006 in conducting the detailed examination step of the ICDA process. In addition, on the first use of ICDA for a covered segment, an operator must identify a minimum of two locations for excavation within each ICDA Region and must perform a detailed examination for internal corrosion at each location, using ultrasonic thickness measurements, radiography, or other generally accepted measurement technique. One location must be the low point (*e.g.,* sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further downstream, within a covered segment, near the end of the ICDA Region. This approach will serve to determine the possible extent of internal corrosion that could exist across the covered segment. If corrosion exists at either location, the operator must—

(i) Evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with §192.933,~~;~~ if the condition is in a covered segment, or in accordance with §~~§~~ 192.485 or ~~and~~ § 192.713 if the condition is not in a covered segment;

(ii) Expand the detailed examination program, whenever internal corrosion is discovered, to determine all locations that have internal corrosion within the ICDA region, and accurately characterize the nature, extent, and root cause of the internal corrosion. In cases where the internal corrosion was identified within the ICDA region but outside the covered segment, the expanded detailed examination program must also include at least two detailed examinations within each covered segment associated with the ICDA region, at the location within the covered segment(s) most likely to have internal corrosion. One location must be the low point (e.g., sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further downstream, within the covered segment. In instances of first use of ICDA for a covered segment, where these locations have already been examined per paragraph (3) of this section, two additional detailed examinations must be conducted within the covered segment; and

(iii) Expand the detailed examination program to evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA region containing the covered segment in which the corrosion was found, and as appropriate, remediate the conditions the operator finds in accordance with §192.933, ~~or~~ § 192.713 or § 192.485, as appropriate.

(4) *Post-assessment evaluation and monitoring.* An operator must conform to ~~comply with~~ ~~the requirements and recommendations in~~ NACE SP0206-2006 in performing the post assessment step of the ICDA process. In addition, ~~the post-assessment requirements and recommendations in NACE SP0206-2006,~~ the evaluation and monitoring process includes—

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

(ii) Validation of the flow modeling calculations by comparison of actual locations of discovered internal corrosion with locations predicted by the model (if the flow model cannot be validated, the ICDA is not feasible for the segment); and

(iii) Continually monitoring each ICDA region which contains a covered segment where internal corrosion has been identified using techniques such as coupons or UT sensors or electronic probes, and by periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this subpart, and risk factors specific to the ICDA region. At a minimum, the monitoring frequency must be two times each calendar year, but at intervals not exceeding 7½ months. If an operator finds any evidence of corrosion products in the ICDA region, the operator must take prompt action in accordance with one of the two following required actions and remediate the conditions the operator finds in accordance with **§ 192.485, §192.713 or** § 192.933**, as appropriate**.

(A) Conduct excavations of, and detailed examinations at, locations downstream from where the electrolyte might have entered the pipe to investigate and accurately characterize the nature, extent, and root cause of the corrosion, including the monitoring and mitigation requirements of § 192.478; or

(B) Assess the covered segment using ~~ILI tools capable of detecting internal corrosion~~ **another integrity assessment method allowed by this subpart.**

Other than ILI, an operator should be able to employ another integrity assessment method allowed by this subpart (e.g., pressure testing).

(5) *Other requirements.* The ICDA plan must also include the following:

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

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

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

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

(b) *General requirements.* An operator using direct assessment as an integrity assessment method to address stress corrosion cracking in a covered pipeline segment must develop and follow an SCCDA plan that **conforms to** ~~meets all requirements and recommendations contained in~~ NACE SP0204-2008 and that implements all four steps of the SCCDA process including pre-assessment, indirect inspection, detailed examination and post-assessment. As specified in NACE SP0204-2008, Section 1.1.7, SCCDA is complementary with other inspection methods such as in-line inspection (ILI) or hydrostatic testing and is not necessarily an alternative or replacement for these methods in all instances. In addition, the plan must provide for—

> Per PHMSA March 2, 2018 GPAC voting slide 1, PHMSA will "revise proposed §192.493 by striking the phrase 'The requirements and recommendations of' from the paragraph." The intent of the GPAC discussion was to apply this approach throughout other code sections were new standards are to be referenced.
>
> Generally, technical standards establish expectations for "conformance" with that standard, not "compliance."

(1) *Data gathering and integration.* An operator's plan must provide for a systematic process to collect and evaluate data for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment in accordance with NACE SP0204-2008, Sections 3 and 4, and Table 1. This process must also include gathering and evaluating data related to SCC at all sites an operator excavates during the conduct of its pipeline operations (both within and outside covered segments) where NACE SP0204-2008, Section 5.3 indicate the potential for SCC. This data gathering process must be conducted in accordance with NACE SP0204-2008, Section 5.3, and must include, at minimum data listed in NACE SP0204-2008, Table 2. Further the following factors must be analyzed as part of this evaluation:

(i) The effects of a carbonate-bicarbonate environment, including the implications of any factors that promote the production of a carbonate-bicarbonate environment such as soil temperature, moisture, the presence or generation of carbon dioxide, and/or Cathodic Protection (CP).

(ii) The effects of cyclic loading conditions on the susceptibility and propagation of SCC in both high-pH and near-neutral-pH environments.

(iii) The effects of variations in applied CP such as overprotection, CP loss for extended periods, and high negative potentials.

(iv) The effects of coatings that shield CP when disbonded from the pipe.

(v) Other factors which affect the mechanistic properties associated with SCC including but not limited to historical and present-day operating pressures, high tensile residual stresses, flowing product temperatures, and the presence of sulfides.

(2) *Indirect inspection.* In addition to **conforming to** ~~the requirements and recommendations of~~ NACE SP0204-2008, section 4, the plan's procedures for indirect inspection must include provisions for conducting ~~at least two above ground surveys~~ inspections using ~~complementary measurement tools~~ methods most appropriate for the pipeline segment based on the data

gathering and integration step, unless the data obtained from the pre-assessment step of NACE SP0204-2008, section 3, is sufficient to prioritize susceptible segments for direct examination.

(3) *Direct examination*. In addition to conforming to ~~the requirements and recommendations of~~ NACE SP0204-2008, the plan's procedures for direct examination must provide for conducting a minimum of three direct examinations within the SCC segment at locations determined to be the most likely for SCC to occur.

PHMSA should revise language to permit operators to select most appropriate tools and methods for SCC detection via indirect inspection for their systems. Above ground surveys using CIS or DCVG may not be effective methods based on the type of coating (shielding vs. non-shielding) and the type of potential SCC (High pH or near neutral pH). Therefore, the regulatory language should not prescribe indirect inspection methods that are not part of the consensus standard for SCCDA, NACE SP0204-2008.

(4) *Remediation and mitigation.* If any indication of SCC is discovered in a segment, an operator must mitigate the threat in accordance with one of the following applicable methods:

(i) Removing the pipe with SCC, remediating the pipe with a Type B sleeve, ~~hydrostatic testing in accordance with (b)(4)(ii), below~~, or by grinding out the SCC defect and repairing the pipe. If grinding is used for repair, the repair procedure must include: nondestructive testing for any remaining cracks or other defects; measuring remaining wall thickness; and the remaining strength of the pipe at the repair location must be determined using ASME/ANSI B31G or RSTRENG and must be sufficient to meet the design requirements of subpart C of this part. Pipe and material properties used in remaining strength calculations must be documented.~~ in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607.~~

The duplicative reference to hydrostatic testing in (i) is confusing and should be removed. Spike testing is addressed in (ii).

(A) If pipe diameter or wall thickness is not known or records are not available, the operator must:

(1) Use the same diameter and/or wall thickness values that are the basis for the current MAOP; or

(2) Verify these properties based upon the material documentation process specified in § 192.607.

PHMSA should revise language for remaining strength calculations on pipe segments without material property records to be consistent with the language in §192.713, which allows operators to use conservative values for material properties.

(B) If SMYS or actual material yield is not known or records are not available, the operator must:

(1) Use the same material properties that are the basis for the current MAOP;

(2) Assume grade A pipe (30 ksi); or

(3) Verify these properties using the material documentation process specified in § 192.607.

(ii) ~~Significant SCC must be mitigated~~ Using a spike pressure test in accordance with §192.506. ~~hydrostatic testing program to a minimum test pressure equal to 105 percent of the specified minimum yield strength of the pipe for 30 minutes immediately followed by a pressure test in accordance with § 192.506, but not lower than 1.25 times MAOP. The test pressure for the entire sequence must be continuously maintained for at least 8 hours, in accordance with § 192.506 and must be above the minimum test factors in §§ 192.619(a)(2)(ii) or 192.620(a)(2)(ii), but not lower than 1.25 times maximum allowable operating pressure.~~ Any test failures due to SCC must be repaired by replacement of the pipe segment, and the segment re-tested. ~~until the pipe passes the complete test without leakage.~~ Pipe segments that have SCC present, but that pass the pressure test assessment criteria, may be repaired by grinding any discovered indications in accordance with paragraph (b)(4)(i).

Per PHMSA response to public comment (12/15/2017 Transcript pg. 143): Replace redundant language on spike test requirements with reference to § 192.506. Also, the reference to significant SCC should be removed, as PHMSA has proposed to remove that definition.

A spike test is a strength test, not a leak test. A pipe can pass assessment criteria with minimal leakage. Identifiable leaks should be repaired and retested. If leakage is evident on a pressure chart and cannot be found in the line pipe, this is appropriate place for instrumented leak survey.

(iii) Evaluating the SCC in accordance with § 192.713 or § 192.933, as applicable, and remediating or monitoring the SCC in accordance with these sections.

In § 192.713 and § 192.933, PHMSA proposes to allow operators to use fracture mechanics modeling (§ 192.712) to evaluate cracking, including SCC, and then remediate or monitor the cracking based on the predicted failure pressure determined through the modeling. For consistency, operators must be allowed to evaluate and manage SCC identified through DA using the same criteria.

(5) *Post assessment*. In addition to conforming to ~~the requirements and recommendations of~~ NACE SP0204-2008, sections 6.3, periodic reassessment, and 6.4, effectiveness of SCCDA, the operator's procedures for post assessment must include development of a reassessment plan based on the susceptibility of the operator's pipe to SCC as well as on the mechanistic behavior of identified cracking. Reassessment intervals must comply with section 192.710 or 192.939 of this part, as applicable. Factors that must be considered include, but are not limited to:

(i) Evaluation of discovered crack clusters during the direct examination step. in accordance with NACE RP0204-2008, sections 5.3.5.7, 5.4, and 5.5;
(ii) Conditions conducive to creation of the carbonate-bicarbonate environment;
(iii) Conditions in the application (or loss) of CP that can create or exacerbate SCC;
(iv) (Operating temperature and pressure conditions including operating stress levels on the pipe;
(v) Cyclic loading conditions;
(vi) Mechanistic conditions that influence crack initiation and growth rates;
(vii) The effects of interacting crack clusters;

(viii) The presence of sulfides; and
(ix) Disbonded coatings that shield CP from the pipe.

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

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

(1) *Temporary pressure reduction.* If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must notify PHMSA in accordance with **§192.635** if it cannot meet the response schedule required under paragraph (c) of this section and cannot provide safety through a temporary reduction in operating pressure or other action. ~~**An operator must also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement or an intrastate covered segment is regulated by that State.**~~ **Operators must document the calculation method(s) or decisions used to determine reduced operating pressure and the implementation of the actual reduced operating pressure for a period of five years after the pipeline has been examined in-field and, if necessary, repaired and the requirement for reduced operating pressure has been eliminated. For any temporary reduction in operating pressure required by this section, the operator must determine temporary reduction in operating pressure using one of the following methods:**

(i) A level that restores the safety margin commensurate with the **pipe** design factor for the Class Location in which the affected pipeline is located, determined using ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991), ~~**or**~~ AGA Pipeline Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)) ("RSTRENG," incorporated by reference, see § 192.7) **or an alternative equivalent method of remaining strength calculation** for corrosion defects. ~~**Both**~~ **These** procedures ~~**apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and**~~ are subject to the limitations prescribed in the equations procedures. **The pipe design factor shall be determined in accordance with the requirements in either §§ 192.111, 192.611(a)(3), or 192.620.** When determining the predicted failure pressure (PFP) for gouges, scrapes, selective seam weld corrosion, crack-related defects, appropriate failure criteria and justification of the criteria must be used~~**. If SMYS or actual material yield and ultimate tensile strength is not known or not adequately documented by reliable, traceable, verifiable, and complete records, then the operator must assume grade A pipe or determine the material properties based upon the material documentation program specified in § 192.607;**~~

(ii) 80% of pressure at the time of discovery; **or** ~~**whichever is lower.**~~

(iii) **A level that restores the safety margin to 1.1 times the predicted failure pressure, determined using ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991), AGA Pipeline Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)) ("RSTRENG," incorporated by reference, see § 192.7), or an alternative equivalent method of remaining strength calculation for corrosion defects. These procedures are subject to the limitations prescribed in the equations procedures. When determining the predicted failure pressure for gouges, scrapes, selective seam weld corrosion, crack-related defects, appropriate failure criteria and justification of the criteria must be used.**

(2) *Long-term pressure reduction.* When a pressure reduction exceeds 365 days, the operator must notify PHMSA under **§192.635** ~~§192.949~~ and explain the reasons for the ~~remediation~~ delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline. ~~The operator also must notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State.~~

(b) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. For the purposes of this section, a condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable. In cases where a determination is not made within the 180-day period the operator must notify OPS, in accordance with **§192.635** ~~§192.949~~, and provide an expected date when adequate information will become available.

(c) *Schedule for evaluation and remediation.* An operator must complete **in-field examination and, if necessary,** remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. Unless a special requirement for **responding to** ~~remediating~~ certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 7, Figure 4. **Manufacturing related features meeting the criteria in paragraph (d) do not require a response if a pressure test has been conducted satisfying the criteria of subpart J to at least 1.25 times the maximum allowable operating pressure.** If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.

(d) *Special requirements for scheduling remediation—*

(1) *Immediate ~~repair~~ conditions.* An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 in providing for immediate ~~repair~~ conditions. To maintain safety, **within 5 days of discovery** an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the **in-field examination and, if necessary,** repair of these conditions. An operator must treat the following conditions as immediate ~~repair~~ conditions:

(i) **For metal loss anomalies, a**~~A~~ calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly ~~for any class location~~. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. Pipe and material properties used in remaining strength calculations must be documented. ~~in reliable~~, ~~traceable, verifiable, and complete records~~ ~~that will provide an equally conservative result. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607.~~

(A) If pipe diameter or wall thickness is not known or records are not available, the operator must:

(1) **Use the same diameter and/or wall thickness values that are the basis for the current MAOP; or**

(2) **Verify these properties based upon the material documentation process specified in § 192.607.**

(B) If SMYS or actual material yield is not known or records are not available, the operator must:

(1) Use the same material properties that are the basis for the current MAOP;

(2) Assume grade A pipe (30 ksi); or

(3) Verify these properties using the material documentation process specified in § 192.607.

(ii) For crack or crack-like anomalies:

(A) Crack depth ~~plus corrosion~~ is greater than 50% of pipe wall thickness, as measured at the crack location; or

(B) ~~Crack depth plus corrosion is greater than the inspection tool's maximum measurable depth; or~~

(B) Fracture mechanics modeling per § 192.712 shows a failure stress pressure at the location of the anomaly less than or equal to 1.1 times the maximum allowable operating pressure.

(iii) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) that has ~~any indication of~~ metal loss, cracking or a stress riser, unless an engineering critical assessment of the dent in accordance with § 192.714 demonstrates that critical strain levels are not exceeded.

(iv) Metal loss greater than 80% of nominal wall regardless of dimensions.

(v) ~~An indication of~~ Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency ~~or high frequency~~ electric resistance welding or by electric flash welding, unless the predicted failure pressure is greater than 1.25 times the maximum allowable operating pressure.

(vi) ~~Any indication of significant stress corrosion cracking (SCC).~~

(vii) ~~Any indication of significant selective seam weld corrosion (SSWC).~~

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

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

(ii) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless engineering analyses of the dent demonstrate critical strain levels are not exceeded.

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

(iv) A dent located between the 4 o'clock position and the 8 o'clock position (bottom ⅓ of the pipe) that has metal loss, cracking or a stress riser, unless an engineering critical assessment of the dent in accordance with § 192.714 demonstrates that critical strain levels are not exceeded.

(v) In Class 3 and 4 locations, a calculation of the remaining strength of the pipe shows a predicted failure pressure ~~ratio (FPR)~~ at the location of the anomaly less than or equal to 1.39 times the maximum allowable operating pressure, unless the predicted failure pressure is greater than or equal to the maximum allowable operating pressure times the reciprocal of the design factor of the installed pipe. ~~1.25 for Class 1 locations, 1.39 for Class 2 locations, 1.67 for Class 3 locations, and 2.00 for Class 4 locations.~~ This calculation must ~~adequately~~ account for the uncertainty associated with the accuracy of the tool used to perform the assessment.

(vi) For crack or crack-like anomalies, fracture mechanics modeling per § 192.712 shows a failure stress pressure at the location of the anomaly less than or equal to 1.39 for class 1 locations or 1.50 for class 2, 3, and 4 locations times the maximum allowable operating pressure, unless the failure stress pressure is greater than or equal to the maximum allowable operating pressure times the reciprocal of the design factor of the installed pipe.

(vii) Metal-loss other than an immediate condition preferentially affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency ~~or high frequency~~ electric resistance welding or by electric flash welding, unless:

(A) The predicted failure pressure is greater than 1.39 for class 1 locations and 1.50 for class 2, 3 and 4 locations times the maximum allowable operating pressure; or

(B) The predicted failure pressure is greater than or equal to the maximum allowable operating pressure times the reciprocal of the design factor of the installed pipe.

(vii) ~~An area of corrosion with a predicted metal loss greater than 50% of nominal wall.~~

(viii) ~~Predicted~~ Metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that ~~could~~ is preferentially affecting a girth weld, unless:

(A) The predicted failure pressure is greater than 1.39 for class 1 locations and 1.50 for class 2, 3 and 4 locations times the maximum allowable operating pressure; or

(B) The predicted failure pressure is greater than or equal to the maximum allowable operating pressure times the reciprocal of the design factor of the installed pipe.

(ix) ~~A gouge or groove greater than 12.5% of nominal wall.~~

(x) ~~Any indication of crack or crack-like defect other than an immediate condition.~~

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

(i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom ⅓ of the pipe).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

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

(vii) A dent that has metal loss, cracking or a stress riser and engineering critical assessment of the dent in accordance with § 192.714 demonstrates that critical strain levels are not exceeded.

(viii) A crack or crack-like anomaly for which fracture mechanics modeling per § 192.712 shows a failure stress pressure at the location of the anomaly that is:

(A) Greater than 1.39 for class 1 locations and 1.50 for class 2, 3 and 4 locations times the maximum allowable operating pressure; or

(B) Greater than or equal to the maximum allowable operating pressure times the reciprocal of the design factor of the installed pipe.

(ix) Metal-loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency ~~or high frequency~~ electric resistance welding or by electric flash welding, where the predicted failure pressure is:

(A) Greater than 1.39 for class 1 locations and 1.50 for class 2, 3 and 4 locations times the maximum allowable operating pressure; or

(B) Greater than or equal to the maximum allowable operating pressure times the reciprocal of the design factor of the installed pipe.

(x) Metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that is preferentially affecting a girth weld where the predicted failure pressure is:

(A) Greater than 1.39 for class 1 locations and 1.50 for class 2, 3 and 4 locations times the maximum allowable operating pressure; or

(B) Greater than or equal to the maximum allowable operating pressure times the reciprocal of the design factor of the installed pipe.

(e) *Repair*. Each imperfection or damage that is verified by in-field examination and requires remediation under paragraph (c) of this section must be repaired to support the current maximum allowable operating pressure of the pipeline segment, considering the design factor of the installed pipe. The imperfection or damage must be –

(1) Removed by cutting out and replacing a cylindrical piece of pipe;

(2) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe; or

(3) Repaired by a repair method defined in ASME B31.8S, Section 7, Table 4.

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

(a) *General requirements.* An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of failure in a high consequence area. Such additional measures must be based on the risk analysis required by 192.917. **Operators** ~~and~~ must **consider** ~~include~~ **the following additional measures for implementation, as necessary** ~~, but are not limited to~~: correction of the root cause of past incidents to prevent reoccurrence; establishing and implementing adequate operations and maintenance processes that could increase safety; establishing and deploying adequate resources for successful execution of preventive and mitigative measures; installing Automatic Shut-off Valves or Remote Control Valves; installing pressure transmitters on both sides of automatic shutoff valves and remote control valves that communicate with pipe control center; installing computerized monitoring and leak detection systems; replacing pipe segments with pipe of heavier wall thickness or higher strength; conducting additional right of way patrols; conducting hydrostatic tests in areas where material has quality issues or lost records; tests to determine material mechanical properties for unknown properties that are need to assure integrity or substantive MAOP evaluations including material property tests from removed pipe that is representative of the in-service pipeline; re-coating of damaged, poorly performing or disbonded coatings; applying additional depth-of-cover survey at roads, streams, and rivers, remediating inadequate depth of cover; providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.

Per the June 6, 2017 GPAC Meeting Vote (Slide 81, Bullet #2), PHMSA will "clarify that it is not PHMSA's intent to require that all listed P&M measures be implemented (& that 'must consider' will be instituted)."

The Associations recommend adding "for implementation, as necessary" to emphasize that operators **must *consider*** these P&M measures, but not implement all measures.

(b) Third party damage and outside force damage—
   (1) *Third party damage.* An operator must enhance its damage prevention program, as required under §192.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures to an existing damage prevention program include, at a minimum—
      (i) Using qualified personnel (*see* §192.915) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.
      (ii) Collecting in a central database information that is location specific on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under part 191.
      (iii) Participating in one-call systems in locations where covered segments are present.
      (iv) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE SP0502 (incorporated by reference, *see* §192.7). An operator must excavate, and remediate, in accordance with ANSI/ASME B31.8S and §192.933 any indication of coating holidays or discontinuity warranting direct examination.

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

(c) [No change from current]

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

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

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

(3) Perform semi-annual, instrumented leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where indirect assessments, i.e. indirect examination tool/method such as close interval survey, alternating current voltage gradient, direct current voltage gradient or equivalent are impractical).

(e) ~~[Withdraw proposed language]~~

(f) ~~[Withdraw proposed language]~~

Per the June 6, 2017 GPAC Meeting Vote (Slide 37), PHMSA will "withdraw all proposed changes to the regulations in 192.935(f) and (g) and Appendix E."

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

The Associations have previously submitted recommended revisions for § 192.937 and recommended that it be included in the transmission mandates rule (the first gas transmission rule). In the event PHMSA decides to include § 192.937 in the second final rule, the recommended revisions are reproduced below. Recommended revisions that are new to these comments are highlighted in yellow. A more detailed discussion of these recommendations is included in the Associations' previous filing on the transmission mandates rule.

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

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

(c) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by any one or more of the following methods for each threat to which the covered segment is susceptible (*see* §192.917). An operator must select the method or methods best suited to address the threats identified to the covered segment (*See* § 192.917). An operator may use an integrity assessment to meet the requirements of this section if the pipeline segment assessment is conducted in accordance with the integrity assessment requirements of § 192.624(c) for establishing MAOP.

(1) Internal inspection tool or tools capable of detecting ~~corrosion, deformation and mechanical damage (including dents, gouges and groves), material cracking and crack-like defects (including stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, or any other~~ threats to which the covered segment is susceptible, as determined by the operator. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493. ~~A person qualified by knowledge, training, and experience~~ An operator must analyze the data obtained from an internal inspection tool to determine if a condition could adversely affect the safe operation of the pipeline. In

addition, an operator must explicitly consider uncertainties in reported results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies;

(2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with §192.939. ~~The use of pressure testing is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms, including stress corrosion cracking, manufacturing and related defect threats, including defective pipe and pipe seams, selective seam weld corrosion, dents and other forms of mechanical damage~~;

(3) "Spike" ~~hydrostatic~~ pressure test in accordance with § 192.506. The use of spike hydrostatic pressure testing is appropriate for **time-dependent cracking threats, such as stress corrosion cracking**;~~, selective seam weld corrosion, manufacturing and related defects, including defective pipe and pipe seams, and other forms of defect or damage involving cracks or crack-like defects;~~

(4) Excavation and *in situ* direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data ~~needed to assess all threats~~, including but not limited to, ultrasonic testing (UT), radiography, and**/or** magnetic particle inspection (MPI);

(5) Guided Wave Ultrasonic Testing (GWUT) conducted as described in Appendix F;

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. ~~Use of direct assessment is allowed only if the line is not capable of inspection by internal inspection tools and is not practical to assess using the methods specified in paragraphs (d)(1) through (d)(5) of this section.~~ An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with, as applicable, the requirements specified in §§192.925, 192.927 or 192.929;

(7) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator choosing this option must notify the Office of Pipeline Safety (OPS) ~~180~~ **90** days before conducting the assessment, in accordance with **§192.633** ~~§192.949 and receive a "no objection letter" from the Associate Administrator of Pipeline Safety. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.~~

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

§192.941 What is a low stress reassessment?

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

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

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

  (2) *Unprotected pipe or cathodically protected pipe where indirect assessments are impractical.* If an indirect assessment is impractical on the covered segment an operator must—

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

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

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

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

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

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

Appendix D to Part 192 – Criteria for Cathodic Protection and Determination Measurements

[No Changes from Current]

Per PHMSA June 2017 GPAC meeting voting slide 22, "To address comments on proposed revisions to Appendix D, withdraw the proposed revisions to Appendix D from the final rule."

Appendix E to Part 192 – Guidance on Determining High Consequence Areas and on Carrying out Requirements in the Integrity Management Rule

[No Changes from Current]

Per PHMSA June 2017 GPAC meeting voting slide 37, ""withdraw all proposed change to the regulations in 192.935(f) and (g), and Appendix E."

Appendix F to Part 192–Criteria for Conducting Integrity Assessments Using Guided Wave Ultrasonic Testing (GWUT)

The Associations have previously submitted recommended revisions for Appendix F and recommended that Appendix F be included in the transmission mandates rule (the first gas transmission rule). In the event PHMSA decides to include Appendix F in the second final rule, the recommended revisions are reproduced below. A more detailed discussion of these recommendations is included in the Associations' previous filing on the transmission mandates rule.

This appendix defines criteria which must be properly implemented for use of Guided Wave Ultrasonic Testing (GWUT) as an integrity assessment method. Any application of GWUT that does not conform to these criteria is considered "other technology" as described by §§ 192.710(c)(7), 192.921(a)(7), and 192.937(c)(7), for which OPS must be notified **90** ~~180~~ days prior to use in accordance with §§ 192.921(a)(7) or 192.937(c)(7). GWUT in the "Go-No Go" mode means that all indications (wall loss anomalies) above the testing threshold (a maximum of **20** ~~5~~% of cross sectional area (CSA) sensitivity) be directly examined, in-line tool inspected, pressure tested or replaced prior to completing the integrity assessment on the cased carrier pipe **or other GWUT application**.

I. *Equipment and Software: Generation.* The equipment and the computer software used are critical to the success of the inspection. Guided Ultrasonic LTD (GUL) Wavemaker G3 or G4 with software version 3 or higher, or equipment and software with equivalent capabilities and sensitivities, must be used.

II. *Inspection Range*. The inspection range and sensitivity are set by the signal to noise (S/N) ratio but must still keep the maximum threshold sensitivity at **20** ~~5~~% cross sectional area (CSA). A signal that has an amplitude that is at least twice the noise level can be reliably interpreted. The greater the S/N ratio the easier it is to identify and interpret signals from small changes. The signal to noise ratio is dependent on several variables such as surface roughness, coating, coating condition, associated pipe fittings (T's, elbows, flanges), soil compaction, and environment. Each of these affects the propagation of sound waves and influences the range of the test. It may be necessary to inspect from both ends of the pipeline segment to achieve a full inspection. ~~In general the inspection range can approach 60 to 100 feet for a 5% CSA, depending on field conditions.~~

III. *Complete Pipe Inspection.* To ensure that the entire pipeline segment is assessed there should be at least a 2 to 1 signal to noise ratio across the entire pipeline segment that is inspected. This may require multiple GWUT shots. Double ended inspections are expected. These two inspections are to be overlaid to show the minimum 2 to 1 S/N ratio is met in the middle. If possible, show the same near or midpoint feature from both sides and show an approximate 5% distance overlap.

IV. *Sensitivity.* The detection sensitivity threshold determines the ability to identify a cross sectional change. The maximum threshold sensitivity cannot be greater than **20** ~~5~~% of the cross sectional area (CSA).
The locations and estimated CSA of all metal loss features in excess of the detection threshold must be determined and documented. All **wall loss** defect indications in the "Go-No Go" mode above the **20** ~~5~~% testing threshold must be directly examined, in-line inspected, pressure tested, or replaced prior to completing the integrity assessment.

V. *Wave Frequency.* Because a single wave frequency may not detect certain defects, a minimum of three frequencies must be run for each inspection to determine the best frequency for characterizing indications. The frequencies used for the inspections must be documented and must be in the range specified by the manufacturer of the equipment.

VI. *Signal or Wave Type: Torsional and Longitudinal*. Both torsional and longitudinal waves must be used **in the course of the assessment** and use must be documented. **In most cases torsional wave will be used for the majority of the assessment and be complemented by longitudinal wave in the areas of the collar.**

VII. *Distance Amplitude Correction (DAC) Curve and Weld Calibration.* The Distance Amplitude Correction curve accounts for coating, pipe diameter, pipe wall and environmental conditions at the assessment location. The DAC curve must be set for each inspection as part of establishing the effective range of a GWUT inspection. DAC curves provide a means for evaluating the cross sectional area change of reflections at various distances in the test range by assessing signal to noise ratio. A DAC curve is a means of taking apparent attenuation into account along the time base of a test signal. It is a line of equal sensitivity along the trace which allows the amplitudes of signals at different axial distances from the collar to be compared.

VIII. *Dead Zone.* The Dead Zone is the area adjacent to the collar in which the transmitted signal blinds the received signal, making it impossible to obtain reliable results. Because the entire line must be inspected, inspection procedures must account for the dead zone by requiring the movement of the collar for additional inspections. An alternate method of obtaining valid readings in the dead zone is to use B-scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.

IX. *Near Field Effects.* The Near Field is the region beyond the Dead Zone where the receiving amplifiers are increasing in power, before the wave is properly established. Because the entire line must be inspected, inspection procedures must account for the near field by requiring the movement of the collar for additional inspections. An alternate method of obtaining valid readings in the near field is to use B-scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.

X. *Coating Type.* Coatings can have the effect of attenuating the signal. Their thickness and condition are the primary factors that affect the rate of signal attenuation. Due to their variability, coatings make it difficult to predict the effective inspection distance.
Several coating types may affect the GWUT results to the point that they may reduce the expected inspection distance. For example, concrete coated pipe may be problematic when well bonded due to the attenuation effects. If an inspection is done and the required sensitivity is not achieved for the entire length of the **assessed** ~~cased~~ pipe, then another type of assessment method must be utilized.

XI. *End Seal.* **When assessing cased carrier pipe with GWUT,** operators must remove the end seal from the casing at each GWUT test location to facilitate visual inspection. Operators must remove debris and water from the casing at the end seals. Any corrosion material observed must be removed, collected and reviewed by the operator's corrosion technician. The end seal does not interfere with the accuracy of the GWUT inspection but may have a dampening effect on the range.

XII. *Weld Calibration to set DAC Curve.* Accessible welds, along or outside the pipe segment to be inspected, must be used to set the DAC curve. A weld or welds in the access hole (secondary area) may be used if welds along the pipe segment are not accessible. In order to use these welds in the secondary area, sufficient distance must be allowed to account for the dead zone and near field. There must not be a weld between the transducer collar and the calibration weld. A conservative estimate of the predicted amplitude for the weld is 25% CSA (cross sectional area) and can be used if welds are not accessible. Calibrations (setting of the DAC curve) should be on pipe with similar properties such as wall thickness and coating. If the actual weld cap height is different from the assumed weld cap height, the estimated CSA may be inaccurate and adjustments to the DAC curve may be required. Alternative means of calibration can be used if justified by sound engineering analysis and evaluation.

XIII. *Validation of Operator Training*. ~~**There is no industry standard for qualifying GWUT service providers.**~~ Pipeline operators must require all guided wave service providers to have equipment-specific training and experience for all GWUT Equipment Operators which includes training for:

A. equipment operation,
B. field data collection, and
C. data interpretation on cased and buried pipe.

Only individuals who have been qualified by the manufacturer or an independently assessed evaluation procedure similar to ISO 9712 (Sections: 5 Responsibilities; 6 Levels of Qualification; 7 Eligibility; and 10 Certification), as specified above, may operate the equipment.

A Senior Level GWUT Equipment Operator with pipeline specific experience must provide onsite oversight of the inspection and approve the final reports. A Senior Level GWUT Equipment Operator must have additional training and experience, including but not limited to training specific to cased and buried pipe, with a quality control program which conforms to Section 12 of ASME B31.8S.

Training and Experience Minimums for Senior Level GWUT Equipment Operators:

- Equipment Manufacturer's minimum qualification for equipment operation and data collection with specific endorsements for casings and buried pipe
- Training, qualification and experience in testing procedures and frequency determination
- Training, qualification and experience in conversion of guided wave data into pipe features and estimated metal loss (estimated cross-sectional area loss and circumferential extent)
- Equipment Manufacturer's minimum qualification with specific endorsements for data interpretation of anomaly features for pipe within casings and buried pipe.

XIV. *Equipment: traceable from vendor to inspection company.* The operator must maintain documentation of the version of the GWUT software used and the serial number of the other equipment such as collars, cables, etc., in the report.

XV. *Calibration Onsite.* The GWUT equipment must be calibrated for performance in accordance with the manufacturer's requirements and specifications, including the frequency of calibrations. A diagnostic check and system check must be performed on-site each time the equipment is relocated **to a different casing or pipe segment**. If on-site diagnostics show a discrepancy with the manufacturer's requirements and specifications, testing must cease until the equipment can be restored to manufacturer's specifications.

XVI. XVI. *Use on Shorted Casings (direct or electrolytic).* ~~**GWUT may not be used to assess shorted casings. GWUT operators must have operations and maintenance procedures (*see § 192 .605)* to address the effect of shorted casings on the GWUT signal.**~~ The equipment operator **must assure the accuracy of the data is not compromised by the shorted casing, and only use data which meets the specification.** ~~**clear any evidence of interference, other than some slight dampening of the GWUT signal from the shorted casing, according to their operating and maintenance procedures.**~~ All shorted casings found while conducting GWUT inspections must be addressed by the operator's standard operating procedures **under 192.605**.

XVII. *Direct examination of all indications above the detection sensitivity threshold.*

The use of GWUT in the "Go-No Go" mode requires that all indications (wall loss anomalies) above the testing threshold (20 ~~5~~% of CSA sensitivity) be directly examined (or replaced) prior to completing the integrity assessment on the cased carrier pipe or other GWUT application. If this cannot be accomplished then alternative methods of assessment (such as hydrostatic pressure tests or ILI) must be utilized.

XVIII. *Timing of direct examination of all indications above the detection sensitivity threshold.* Operators must either replace or conduct direct examinations of all indications (wall loss anomalies) identified above the detection sensitivity threshold according to the table below. Operators must conduct leak surveys and reduce operating pressure as specified until the pipe is replaced or direct examinations are completed.

Required Response to GWUT Wall Loss Indications			
GWUT Criterion	Operating Pressure less than or equal to 30% SMYS	Operating pressure over 30 and less than or equal to 50% SMYS	Operating pressure over 50% SMYS
Over the detection sensitivity threshold (maximum of 20 ~~5~~% CSA)	Replace, ~~or~~ direct examination, or alternative assessment, within 12 months, and instrumented leak survey once every 30 calendar days.	Replace, ~~or~~ direct examination, or alternative assessment, within 6 months, and instrumented leak survey once every 30 calendar days, and maintain MAOP below the highest actual operating pressure sustained by the pipeline within two years prior to ~~at time of~~ discovery.	Replace, ~~or~~ direct examination, or alternative assessment, within 6 months, and instrumented leak survey once every 30 calendar days, and reduce MAOP to 80% of the highest actual operating pressure sustained by the pipeline within two years prior to ~~at time of~~ discovery.

IV. Restructuring § 192.711, § 192.713 and § 192.933 to minimize duplication

To avoid duplication and potential confusion as § 192.713 and § 192.933 are revised over time, PHSMA should consider revising § 192.713 so that it a process for anomaly remediation that can be referenced for both pipelines covered by Subpart O and for pipelines not covered by Subpart O that operate above 40% of SMYS. To demonstrate how these sections might be constructed to eliminate this duplication, the Associations recommend the revisions below. The highlighted language signifies revisions that the Associations are recommending to minimize duplication that are different than the recommended revisions in Section III above.

§192.711 Transmission lines: General requirements for repair procedures.

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

(1) A leak, imperfection, or damage that **requires an immediate response under § 192.713(d)(1)** ~~**impairs its serviceability**~~ is found in a segment of steel transmission line operating at or above 40 percent of the SMYS **or in a segment covered under Subpart O-Gas Transmission Pipeline Integrity Management** and it is not feasible to make a permanent repair at the time of discovery~~.~~**; or**

(2) A leak, imperfection, or damage that requires a scheduled response under § 192.713(d)(3) is found in a segment of steel transmission line operating at or above 40 percent of the SMYS or a segment covered under Subpart O-Gas Transmission Pipeline Integrity Management and it is not feasible to make a permanent repair within the required timeframe.

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

(1) ~~**Non-integrity management repairs:**~~ **For assessments completed after [*the effective date of the rule*],** whenever an operator discovers a~~**ny**~~ condition ~~**that could adversely affect the safe operation of**~~ **on** a **segment of steel transmission line operating at or above 40 percent of the SMYS** ~~**pipeline**~~ **and** not covered under subpart O–Gas Transmission Pipeline Integrity Management, it must **address** ~~**correct**~~ the condition as prescribed in § 192.713**(d). An operator must address any scheduled conditions meeting the criteria in §192.713(d)(3) within two years of discovery.** ~~**However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator must reduce the operating pressure to a level not exceeding 80% of the operating pressure at the time the condition was discovered and take additional immediate temporary measures in accordance with paragraph (a) to protect persons or property. The operator must make permanent repairs as soon as feasible.**~~

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

§192.713 Transmission lines: Permanent field repair of imperfections and damages.

~~(a) This section applies to transmission lines. Line segments that are located in high consequence areas, as defined in 192.903, must comply with applicable actions specified by the integrity management requirements in subpart O.~~

(a) *General*. Each operator must, in repairing imperfections and damages to its pipeline systems, ensure that the repairs are made in a safe manner and are made so as to prevent damage to persons, property, or the environment. Operating pressure must be at a safe level during repair operations.

(b) *Repair*. Each imperfection or damage that is verified by in-field examination and requires remediation under paragraph (d) of this section ~~impairs the serviceability of~~ ~~pipe in a steel transmission line operating at or above 40 percent of SMYS~~ must be repaired to support the current maximum allowable operating pressure of the pipeline segment, considering the design factor of the installed pipe. The imperfection or damage must be —

(1) Removed by cutting out and replacing a cylindrical piece of pipe; ~~or~~

(2) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe; or

(3) Repaired by a repair method defined in ASME B31.8S, Section 7, Table 4.

(c) *Remediation schedule*. ~~For pipelines not located in high consequence areas,~~ An operator must complete the in-field examination and, if necessary, remediation of a condition identified by an assessment completed after [*the effective date of the rule*] according to the schedules in this paragraph. Unless a special requirement for responding to certain conditions applies, as provided in this paragraph, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 7, Figure 4. Manufacturing related features meeting the criteria in this paragraph do not require a response if a pressure test has been conducted satisfying the criteria of subpart J to at least 1.25 times the maximum allowable operating pressure. If an operator cannot meet the schedule for any condition, the operator must document the reason(s) why it cannot meet the schedule and how the changed schedule will not jeopardize public safety. ~~following schedule:~~

(1) *Immediate ~~repair~~ conditions*. An operator must address ~~repair~~ the following conditions immediately upon discovery:

(i) For metal loss anomalies, a~~A~~ calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in § 192.7(c). Pipe and material properties used in remaining strength calculations must be documented.~~in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607.~~

(A) If pipe diameter or wall thickness is not known or records are not available, the operator must:

(1) Use the same diameter and/or wall thickness values that are the basis for the current MAOP; or

(2) Verify these properties based upon the material documentation process specified in § 192.607.

(B) If SMYS or actual material yield is not known or records are not available, the operator must:

(1) Use the same material properties that are the basis for the current MAOP;
(2) Assume grade A pipe (30 ksi); or
(3) Verify these properties using the material documentation process specified in § 192.607.

(ii) Metal loss greater than 80% of nominal wall regardless of dimensions.

(iii) ~~An indication of~~ Metal-loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency ~~or high frequency~~ electric resistance welding or by electric flash welding, unless the predicted failure pressure is greater than 1.25 times the maximum allowable operating pressure.

For clarity, PHMSA should consider re-ordering each of the immediate, scheduled and monitored criteria by threat type so that the order is consistent within each subparagraph. The Associations recommend listing all metal loss criteria first, followed by dent criteria, followed by cracking criteria, as demonstrated here.

(iv) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) that has ~~any indication of~~ metal loss, cracking or a stress riser, unless an engineering critical assessment of the dent in accordance with § 192.714 demonstrates that critical strain levels are not exceeded.

(v) For crack or crack-like anomalies:

(A) Crack depth ~~plus corrosion~~ is greater than 50% of pipe wall thickness, as measured at the crack location; or

(B) ~~Crack depth plus corrosion is greater than the inspection tool's maximum measurable depth; or~~

(C) Fracture mechanics modeling per § 192.712 shows a failure stress pressure at the location of the anomaly less than or equal to 1.1 times the maximum allowable operating pressure.

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

(vii) ~~Any indication of significant stress corrosion cracking (SCC).~~

(viii) ~~Any indication of significant selective seam weld corrosion (SSWC).~~

(2) Until the in-field examination and, if necessary, remediation of a condition specified in paragraph (d)(1) is complete, an operator must reduce the operating pressure of the affected pipeline within 5 days of discovery of the condition in accordance with 192.713(d)(5). ~~to the lower of:~~

(i) ~~A level that restores the safety margin commensurate with the design factor for the Class Location in which the affected pipeline is located, determined using ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991), or AGA Pipeline Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)) ("RSTRENG," incorporated by reference, see § 192.7) for corrosion defects. Both procedures apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations procedures. When determining the predicted failure pressure (PFP) for gouges, scrapes, selective seam weld corrosion, crack-related defects, appropriate failure criteria and justification of the criteria must be used. If SMYS or actual material yield and ultimate tensile strength is not known or not adequately documented by reliable, traceable, verifiable, and complete records, then the~~

~~operator must assume grade A pipe or determine the material properties based upon the material documentation program specified in § 192.607, or~~

(ii) ~~80% of pressure at the time of discovery~~~~, whichever is lower~~.

(3) *Scheduled* ~~*Two-year*~~ *conditions*. An operator must address ~~repair~~ the following conditions according to the schedule established in § 192.711(b)(1) or § 192.933, as applicable. ~~within two years of discovery:~~

(i) In Class 3 and 4 locations, a calculation of the remaining strength of the pipe shows a predicted failure pressure ~~ratio (FPR)~~ at the location of the anomaly less than or equal to 1.39 times the maximum allowable operating pressure, unless the predicted failure pressure is greater than or equal to the maximum allowable operating pressure times the reciprocal of the design factor of the installed pipe. ~~1.25 for Class 1 locations, 1.39 for Class 2 locations, 1.67 for Class 3 locations, and 2.00 for Class 4 locations.~~ This calculation must ~~adequately~~ account for the uncertainty associated with the accuracy of the tool used to perform the assessment.

(ii) Metal-loss other than an immediate condition preferentially affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency ~~or high frequency~~ electric resistance welding or by electric flash welding, unless:

(A) The predicted failure pressure is greater than 1.39 for class 1 locations and 1.50 for class 2, 3 and 4 locations times the maximum allowable operating pressure; or

(B) The predicted failure pressure is greater than or equal to the maximum allowable operating pressure times the reciprocal of the design factor of the installed pipe.

(iii) ~~Predicted~~ Metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that ~~could~~ is preferentially affecting a girth weld, unless:

(A) The predicted failure pressure is greater than 1.39 for class 1 locations and 1.50 for class 2, 3 and 4 locations times the maximum allowable operating pressure; or

(B) The predicted failure pressure is greater than or equal to the maximum allowable operating pressure times the reciprocal of the design factor of the installed pipe.

(xi) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless engineering analyses of the dent demonstrate critical strain levels are not exceeded.

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

(iv) A dent located between the 4 o'clock position and the 8 o'clock position (bottom ⅓ of the pipe) that has metal loss, cracking or a stress riser, unless an engineering critical assessment of the dent in accordance with § 192.714 demonstrates that critical strain levels are not exceeded.

(v) For crack or crack-like anomalies, fracture mechanics modeling per § 192.712 shows a failure stress pressure at the location of the anomaly less than or equal to 1.39 for class 1 locations or 1.50 for class 2, 3, and 4 locations times the maximum allowable operating pressure, unless the failure stress pressure is greater than or equal to the maximum allowable operating pressure times the reciprocal of the design factor of the installed pipe.

(vi) ~~An area of corrosion with a predicted metal loss greater than 50% of nominal wall.~~

(vii) ~~A gouge or groove greater than 12.5% of nominal wall.~~

(viii) ~~Any indication of crack or crack-like defect other than an immediate condition.~~

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

(i) **Metal-loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency ~~or high frequency~~ electric resistance welding or by electric flash welding, where the predicted failure pressure is:**

(A) Greater than 1.39 for class 1 locations and 1.50 for class 2, 3 and 4 locations times the maximum allowable operating pressure; or

(B) Greater than or equal to the maximum allowable operating pressure times the reciprocal of the design factor of the installed pipe.

(ii) **Metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that is preferentially affecting a girth weld where the predicted failure pressure is:**

(A) Greater than 1.39 for class 1 locations and 1.50 for class 2, 3 and 4 locations times the maximum allowable operating pressure; or

(B) Greater than or equal to the maximum allowable operating pressure times the reciprocal of the design factor of the installed pipe.

(iii) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the pipe).

(iv) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

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

(vi) **A dent that has metal loss, cracking or a stress riser and engineering critical assessment of the dent in accordance with** § 192.714 **demonstrates that critical strain levels are not exceeded.**

(vii) **A crack or crack-like anomaly for which fracture mechanics modeling per § 192.712 shows a failure stress pressure at the location of the anomaly that is:**

(A) Greater than 1.39 for class 1 locations and 1.50 for class 2, 3 and 4 locations times the maximum allowable operating pressure; or

(B) Greater than or equal to the maximum allowable operating pressure times the reciprocal of the design factor of the installed pipe.

(5) ***Temporary pressure reduction.*** **If an operator is unable to respond within the time limits for conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline segment or take other action that ensures the safety of the pipeline segment. An operator must notify PHMSA in accordance with** §192.635 **if it cannot meet the response schedule required under paragraph (d) of this section and cannot provide safety through a temporary reduction in operating pressure or other action. Operators must document the calculation method(s) or decisions used to determine reduced operating pressure and the implementation of the actual reduced operating pressure for a period of five years after the pipeline has been** examined and, if necessary, **repaired** and the requirement

for reduced operating pressure has been eliminated. For any temporary reduction in operating pressure required by this section, the operator must determine temporary reduction in operating pressure using one of the following methods:

(i) A level that restores the safety margin commensurate with the pipe design factor for the Class Location in which the affected pipeline is located, determined using ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991), ~~or~~ AGA Pipeline Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)) ("RSTRENG," incorporated by reference, see § 192.7) or an alternative equivalent method of remaining strength calculation for corrosion defects. ~~Both~~ These procedures ~~apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and~~ are subject to the limitations prescribed in the equations procedures. The pipe design factor shall be determined in accordance with the requirements in either §§ 192.111, 192.611(a)(3), or 192.620. When determining the predicted failure pressure (PFP) for gouges, scrapes, selective seam weld corrosion, crack-related defects, appropriate failure criteria and justification of the criteria must be used~~. If SMYS or actual material yield and ultimate tensile strength is not known or not adequately documented by reliable, traceable, verifiable, and complete records, then the operator must assume grade A pipe or determine the material properties based upon the material documentation program specified in § 192.607;~~

(ii) 80% of pressure at the time of discovery; or ~~whichever is lower.~~

(iii) A level that restores the safety margin to 1.1 times the predicted failure pressure, determined using ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991), AGA Pipeline Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)) ("RSTRENG," incorporated by reference, see § 192.7) or an alternative equivalent method of remaining strength calculation for corrosion defects. These procedures are subject to the limitations prescribed in the equations procedures. When determining the predicted failure pressure (PFP) for gouges, scrapes, selective seam weld corrosion, crack-related defects, appropriate failure criteria and justification of the criteria must be used.

(6) *Long-term pressure reduction.* When a pressure reduction exceeds 365 days, the operator must submit a notification in accordance with §192.635 and explain the reason for the response delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline.

(e) *Other conditions*. Unless another timeframe is specified in paragraph (d) of this section, an operator must take appropriate remedial action to correct any condition that could adversely affect the safe operation of a pipeline system in accordance with the criteria, schedules and methods defined in the operator's Operating and Maintenance procedures.

(f) *In situ direct examination of crack defects*. Whenever required to examine an anomaly as required by paragraph (d) of this section ~~by this part~~, operators must perform direct examination of known locations of cracks or crack-like defects using inverse wave field extrapolation (IWEX), phased array, automated ultrasonic testing (AUT), or equivalent technology that has been validated to detect tight cracks (equal to or less than 0.008 inches crack opening). In-the-ditch examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection and in metallurgy and fracture mechanics for accuracy for the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations.

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

(a) *General requirements.* An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate **conditions as required by §192.713.** ~~those that could reduce a pipeline's integrity.~~ **An operator must complete in-field examination and, if necessary, remediate any scheduled conditions meeting the criteria in §192.713(d)(3) within one year of discovery.** An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment.

(1) ~~*Temporary pressure reduction.* If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must determine any temporary reduction in operating pressure required by this section using ASME/ANSI B31G (incorporated by reference, *see* §192.7); AGA Pipeline Research Council, International, PR-3-805 (R-STRENG) (incorporated by reference, *see* §192.7) to determine the safe operating pressure that restores the safety margin commensurate with the design factor for the Class Location in which the affected pipeline is located, or by reducing the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. Pipe and material properties used in the remaining strength calculation must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based in accordance with §192.607. An operator must notify PHMSA in accordance with §192.949 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through a temporary reduction in operating pressure or through another action. An operator must also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement or an intrastate covered segment is regulated by that State.~~

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

(b) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline in accordance with §192.713. ~~For the purposes of this section, a condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section.~~ An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable. In cases where a determination is not made within the 180-day period the operator must notify OPS, in accordance with **§192.635** ~~§192.949~~, and provide an expected date when adequate information will become available.

(c) ~~*Schedule for evaluation and remediation.* An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by~~

~~reference, see §192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.~~

(d) ~~*Special requirements for scheduling remediation*—~~

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

(i) ~~Calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly for any class location. Suitable remaining strength calculation methods include ASME/ANSI B31G (incorporated by reference, *see* §192.7), PRCI PR-3-805 (R-STRENG) (incorporated by reference, *see* §192.7), or an alternative equivalent method of remaining strength calculation that will provide an equally conservative result. Pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607.~~

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

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

(iv) ~~Metal loss greater than 80% of nominal wall regardless of dimensions.~~

(v) ~~An indication of metal-loss affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency, or high frequency electric resistance welding or by electric flash welding.~~

(vi) ~~Any indication of significant stress corrosion cracking (SCC).~~

(vii) ~~Any indication of significant selective seam weld corrosion (SSWC).~~

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

(i) ~~A smooth dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).~~

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

(iii) ~~A calculation of the remaining strength of the pipe shows a predicted failure pressure ratio at the location of the anomaly less than or equal to 1.25 for Class 1 locations, 1.39 for Class 2 locations, 1.67 for Class 3 locations, and 2.00 for Class 4 locations.~~

(iv) ~~An area of general corrosion with a predicted metal loss greater than 50% of nominal wall.~~

(v) ~~Predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld.~~

(vi) ~~A gouge or groove greater than 12.5% of nominal wall.~~

(vii) ~~Any indication of crack or crack-like defect other than an immediate condition.~~

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

(i) ~~A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom ⅓ of the pipe).~~

(ii) ~~A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.~~

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

Respectfully submitted,
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