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REGULATORY UPDATE MANAGEMENT

US REGULATIONS—1

Regulatory updates place premium on testing, records management

Kofi S. Inkabi
Exponent
Oakland, Calif.

Elizabeth K. Reilly
Exponent
Menlo Park, Calif.

TRANSPORTATION

In addition to ensuring the reliability of records, material verification tests provide operators with an opportunity to better understand their systems' material attributes. Innovative information and records management strategies can evaluate the accuracy of historical records, including material verification and validation processes to capture, store, and analyze this information. Continued advancements in nondestructive examination and information technology show potential to further enhance both the industry's efficiency and visibility in managing these issues and the overall safety of pipeline operations.

Background

US pipelines move nearly two-thirds of the natural gas transported annually. They are the only feasible method for moving the enormous quantities of natural gas and crude oil our society and economy demand.

Relatively recent pipeline failures have made the safety of onshore pipeline systems a major concern, in terms of both injuries to people and the potential for environmental damage. On Sunday, July 25, 2010, a segment of 30-in. OD pipeline ruptured in Marshall, Mich.[1] The rupture released an estimated 843,444 gal of crude oil into the surrounding wetlands. A few months later, on Sept. 9, 2010, a segment of 30-in. OD pipeline ruptured in a residential community of San Bruno, Calif.[2] The rupture resulted in 8 fatalities, 58 injuries, 38 homes destroyed, and 70 homes damaged.

In response to a series of recommendations issued by the US National Transportation Safety Board (NTSB) and its subsequent mandate in the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (HR 2845), the Pipeline and Hazardous Materials Safety Administration (PHMSA) has led a multiyear effort with the onshore natural gas and hazardous liquid pipeline industry to evaluate the adequacy of existing integrity management requirements and to develop a strategy for

RECORDS NEEDED TO REESTABLISH MAOP

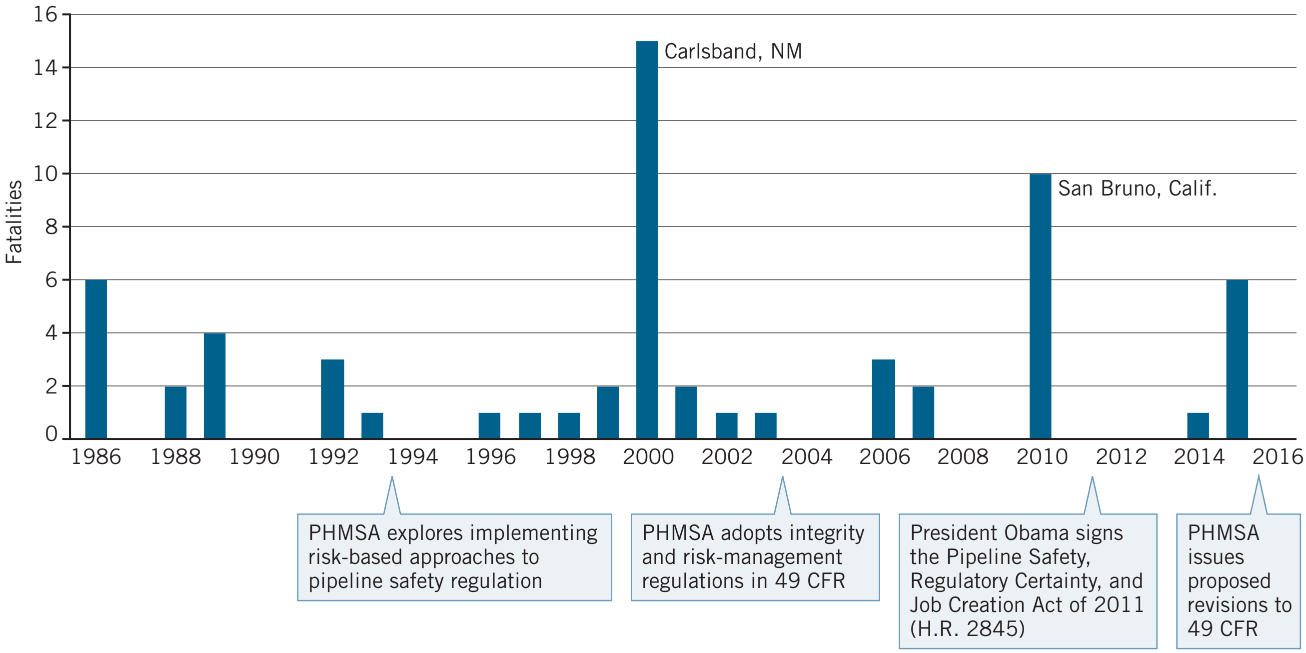
Table 1

MAOP determination method	Example records
192.619(a)(1): Design Pressure	Pipe mill tests (mechanical and chemical properties), as-built drawings, alignment sheets, specifications; design, construction, inspection, and maintenance documents
192.619(a)(2): Post-Construction Pressure Test	Pressure test reports, pressure charts, etc.
192.619(a)(3): Highest Actual Operating Pressure during 5 years preceding July 1, 1970	Historic operating pressure charts, regulator station inspection reports showing inlet or outlet pressures, etc.
192.619(a)(4): Operator Determined	Inspection reports, engineer's evaluation
192.619(c): Grandfather Clause - Highest Actual Operating Pressure during 5 years preceding 1970, even if this MAOP is higher than pressures determined by other (a) methods	Historic operating pressure charts, regulator station inspection reports showing inlet or outlet pressures, etc.
192.619(d): Alternative MAOP	Design records, operating and maintenance procedures, review and any needed program upgrade of the damage prevention program, remote monitoring and control, girth weld NDE records

Sources: PHMSA Advisory Bulleting 2012-06, AGA Verification of MAOPs for Existing Steel Transmission Pipelines

SERIOUS ONSHORE GAS TRANSMISSION ACCIDENTS

FIG. 1



addressing issues and gaps. PHMSA found that some of the existing rules needed to be clarified, existing integrity management requirements needed to be enhanced, and the level of safety of some locations outside of existing high-consequence areas (HCAs), including gathering lines, needed to be improved.

On Apr. 8, 2016, PHMSA formally issued specific changes to 47 different code sections and 4 appendixes within 49 CFR 191 and 192 to fulfill the requirements of HR 2845. Fig. 1 presents a timeline of the regulatory action.

Significant changes included new requirements for:

• Expansion of integrity management principles and maintenance practices to newly defined moderate consequence areas (MCAs), including highways, freeways, five or more buildings, or occupied sites within the potential impact radius.

• Reestablishing maximum-allowable operating pressure (MAOP) within 15 years via a pressure test, pressure reduction, engineering critical assessment, pipe replacement, or other PHMSA-approved technology for Class 3 or 4, HCA, or MCA transmission pipelines, where: (1) the existing basis is §192.619(c) [grandfather clause]; (2) records are not reliable, traceable, verifiable, or complete; or (3) a reportable incident has occurred since the last pressure test.

• Requiring material validation, including verification of records used to establish MAOP and material testing every time a pipeline is exposed in Class 3 or 4 or HCA to help ensure the basis for establishing MAOP accurately reflects the pipeline's physical and operational characteristics.

• Corrosion control and evaluation, including new requirements for performing electrical surveys under various conditions, more detailed requirements for interference and internal corrosion programs, more definition on remediation timelines, an update on the acceptance criteria for cathodic protection, and updates to the requirements for internal corrosion direct assessment and stress corrosion cracking direct assessment.

• Management of change processes, as outlined in ASME/ANSI B31.8S, Section 11.

• New sections in Subparts A through O for records requirements. 49 CFR 192's Appendix A provides a list of those new sections as well as records retention requirements.

Integrity management

The changes proposed by the PHMSA Notice of Proposed Rulemaking (NPRM), if approved, will affect every aspect of how operators structure their integrity management plans. The most significant changes affect:

- Coverage area expansion.
- Prescriptive data gathering and integration.
- Risk assessment validation.
- Assessment method limitation and usage.
- Preventative and mitigative measures.

Coverage area expansion

The NPRM greatly expands the applicable coverage area of integrity management principles and maintenance practices under Subpart M (Maintenance) and Subpart O (Gas Transmission Integrity Management Program,

PROPOSED MAOP REESTABLISHMENT CRITERIA, SYSTEM IMPACTS Table 2

Criteria for NPRM MAOP reestablishment criteria	49 CFR 192	Applicable locations	Onshore gas transmission impact
§192.619(c) [grandfather clause]	192.619(e)	Class 3 or 4, HCA, newly defined MCA	Pressure testing, ~5,000-13,000 miles
Strength test, associated records deficient	192.624(a)(3)	Class 3 or 4, HCA	MAOP records review and pressure testing, ~2,000 miles
Reportable incident since last pressure test	192.619(e)	Class 3 or 4, HCA, newly defined MCA	Pressure testing, 100 miles

or TIMP) by introducing a new classification of pipeline segments: MCAs. MCAs include highways, freeways, and five or more co-located buildings or occupied sites within a potential impact radius not currently defined as an HCA.[3] Subpart O of the current federal code applies only to pipeline segments in HCAs, roughly 7% of the US natural gas transmission pipeline infrastructure. PHMSA estimates the proposed change would expand the integrity management coverage area by about 70,000 miles from the 19,615 HCA miles reported in 2013 as part of the natural gas transmission pipeline system.[4]

Operators must assess the integrity of the newly identified mileage within 15 years of the new rules taking effect. Doing so will require identifying the mileage associated with an MCA and determining the pace required to complete baseline integrity assessments.

Collecting the data associated with this baseline assessment and integrating it with existing enterprise systems within the timeframe allowed will require great effort, given such a large expansion in the integrity assessment area. The common practice of siting pipeline near roadways for ease of access also may exacerbate the new requirement's impact, expanding the mileage requiring regular integrity or maintenance assessments and forcing operators to restructure their approaches to regulatory compliance.

Data gathering, integration

Section 192.917 previously allowed operators to base their data gathering and integration approach on ASME/ANSI B31.8S, according to what is applicable in each threat category (Section 4).[5] The NPRM, however, is greatly expanding this requirement to include:

- 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.
- Close-interval survey and electrical survey results.
- Cathodic protection rectifier readings.
- CP test point survey readings and locations.
- AC/DC and foreign structure interference surveys.
- 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 DC voltage gradient or AC voltage gradient inspections.
- Results of examinations of exposed portions of buried pipelines (e.g., pipe and pipe-coating condition, see §192.459), including the results of any nondestructive examinations of the pipe, seam, or girth weld (i.e., bell-hole inspections).
- Stress corrosion cracking excavations and findings.
- Selective seam weld corrosion excavations and findings.
- Gas stream sampling and internal corrosion monitoring results, including cleaning-pig sampling results.

Section 192.917 includes 45 separate data items, so the list above is not inclusive, instead representing the prescriptive nature of the new regulations' data collection methodology. Regulators have designed a data collection methodology based broadly on a threat identification and inspection program. An operator may have to collect, analyze, and store a large amount of data for a pipeline and subsequently define the risks associated. The operator will also have to verify and validate the data. Operators should seek further information from PHMSA on what is required for these verification and validations steps, because compliance may be labor intensive and potentially difficult to prove under audit.

The rule changes also seek to greatly reduce bias from inputs provided by subject matter experts. At the time of publication PHMSA had not proposed specific control measures to accomplish this bias reduction. In lieu of specific bias control requirements, operators may want to consider developing formal expert assessment protocols, processes, and training, including contributions from external technical experts to fill knowledge gaps and provide fresh perspectives within the organization.

In accordance with ASME/ANSI B31.8S recommendations, PHMSA also has proposed requiring data be analyzed for spatially interacting threats when conducting a risk assessment.[6]

Risk-assessment validation

The fundamentals of risk assessment do not change; the operator must identify the likelihood of threats and the consequences of an incident on each pipeline segment.

The NPRM proposes requiring operators validate the risk assessment methodology implemented. Specifically, PHMSA states that risk assessment validation activities "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 of loss of pipeline integrity and consequences of the postulated loss of pipeline integrity."

The proposed rules also require that the assessment method "account for, and compensate for, uncertainties in the model and the data used in the risk assessment." Capturing and incorporating successes from ongoing research and development activities and operational experience should be considered in addition to past incidents, because an operator's understanding is improved through both success and failure.

MAOP, material validation

The primary objective of a pipeline operator is to construct and maintain a system that will reliably transport products during its lifetime at the lowest total cost. One of the most critical operational design attributes of a pipeline is its MAOP. This attribute largely defines the margin of safety to the public and environment as well as operational flexibility and serviceability. The burst capacity of a pipeline is a function of material properties (yield and tensile strengths), geometry (diameter, WT), manufacturing process (longitudinal seam, girth weld), and condition (wall loss, dents, cracks, etc.). As evidenced by several recent costly failures, effective integrity management requires comprehension of what is known, unknown, and uncertain. It also requires robust processes to collect, maintain, access, and evaluate information.

Section 23 of HR 2845 directs the government to issue regulations to:

- Ensure records accurately reflect the physical and operational characteristics of the pipelines in Class 3 and Class 4 locations and Class 1 and Class 2 HCA.
- Confirm the established MAOP of the pipelines.[7]

In response to this law, PHMSA has introduced §192.624, "Maximum allowable operating pressure verification: Onshore steel transmission pipelines," and modification §192.619, "Maximum allowable operating pressure: Steel or plastic pipelines," which would require operators to reestablish MAOP via a pressure test, pressure reduction, engineering critical assessment, pipe replacement, or other PHMSA-approved alternative technology.

The proposed rules apply to segments of the transmission pipeline system where public exposure is the greatest, specifically Class 3 or 4, HCA, and newly defined MCA segments where:

- The existing basis is §192.619(c) [grandfather clause].
- A reportable incident has occurred since the last pressure test (e.g., manufacturing-related defect or cracking-related defect).
- The existing basis is a strength test and associated records are not reliable, traceable, verifiable, or complete and located in Class 3 or 4 or HCA.

Table 1 provides examples of records that can be used to fulfill the recordkeeping portion of the proposed rule depending on the MAOP determination method of choice.

Although these changes address many of the issues and concerns that NTSB raised subsequent to its investigation of the San Bruno incident,[2] questions remain with respect to its implementation. For example, the NPRM does not specify what will constitute a reliable record and associated thresholds for the purposes of MAOP confirmation. The effective date of incidents that would require a pressure test also remains unspecified, leaving the door open to retroactive testing.

Initial studies suggest that requiring the reestablishment of MAOP for applicable segments currently determined by §192.619(c) will have its greatest impact on industry, principally via the MCAs. In 2013 PHMSA estimated that about 50,000 miles (25%) of Class 1 and 2 non-HCA pipe could be reclassified as MCA pipe. According to PHMSA, about 14% of the transmission system's MAOP is currently established under the grandfather clause, 12% of which is in HCA or Class 3 or 4 locations (about 5,000 miles of pipe). When MCAs are included this number could grow to as much as 13,000 miles (see Table 2).

Data from American Gas Association member companies and PHMSA, by comparison, indicate roughly 5,000 miles of the transmission pipeline infrastructure's MAOP is currently established by a pressure test in an HCA or Class 3 or 4 location that either has not completed an MAOP reconfirmation records review or has found the information to be deficient for this purpose.[8 9]

The NPRM would require operators be in full compliance within 15 years of the effective date of the regulation. Impacts will vary significantly depending on system configuration and records management history (including those of purchased entities over time). Operators should develop strategies to address:

- Expansion of hydrotest programs (including hydrotest failure analysis).
- Increased pipeline replacement projects.
- Shortage of skilled and experienced contractors.
- Strain on outage management resources (e.g., control room, mobile units).
- Rate case testimony, project justification.
- Material procurement, availability.

The NPRM also proposes to modify §192.607, Verification of Pipeline Material: Onshore Steel Transmission Pipelines, to ensure records accurately reflect the physical and operational characteristics of the pipelines per HR 2845 by requiring operators verify material properties through a series of validation tests in Class 3 and 4 locations and in HCAs where reliable, traceable, verifiable, and complete (RTVC) records are not available, regardless of the MAOP determination method chosen.

Although an operator may have performed a strength test and may have supporting RTVC documentation (pressure test record, chart, etc.), if the pipe is located in an HCA or Class 3 or 4 location, manufacturing records (e.g., mill test) or material validation tests will be required. The quantity of material verification tests required depends largely on the quantity of pipe missing documentation and the number of joints exposed.

If an operator elects to use nondestructive techniques (i.e., scratch resistivity-Mohs hardness, instrumented indentation technique, ultrasonic contact impedance, or magnetic flux leakage) to determine strength or chemical composition, the operator must use methods, tools, procedures, and techniques that have been independently validated by subject matter experts in metallurgy and fracture mechanics to produce results accurate within 10% of the actual value with 95% confidence for strength values, within 25% of the actual value with 85% confidence for carbon, and within 20% of the actual value with 90% confidence for manganese, chromium, molybdenum, and vanadium for the grade of steel being tested. OGJ

Part 2 of this article, its conclusion, will appear in the Dec. 5, 2016, issue of Oil & Gas Journal.

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The authors

Kofi Inkabi (kinkabi@exponent.com) is a senior associate at Exponent, Oakland, Calif. He holds a PhD in civil and environmental engineering with an emphasis in risk assessment and management (2009) and an MS in structural engineering, mechanics, and materials (2000) from the University of California, Berkeley, and a BS in civil and environmental Engineering from the University of California, Davis. He is a member of the American Society of Mechanical Engineers, Center for Catastrophic Risk Management, and serves on the American Gas Association's Distribution and Transmission Engineering Committee.

Elizabeth Reilly (ereilly@exponent.com) is a senior managing engineer at Exponent, Menlo Park, Calif. She holds a PhD in mechanical engineering with an emphasis in mechanics of materials (2007) from the University of California, Berkeley, and a BS with honors in chemical engineering from Brown University, Providence, RI. She is a licensed professional engineer in California, and serves on the American Gas Association's Transmission Pipeline Operations Committee. Reilly is also a project management professional (PMP) and a registered patent agent with the US Patent and Trademark Office.

US REGULATIONS—CONCLUSION

US pipeline industry preparing for regulatory changes

Kofi S. Inkabi
Exponent
Oakland, Calif.

Elizabeth K. Reilly
Exponent
Menlo Park, Calif.

Significant regulatory changes are coming to the pipeline industry. Its members are responding to the Pipeline and Hazardous Materials Safety Administration (PHMSA) regarding proposed regulatory changes to 49 Code of Federal Regulations (CFR) Part 192 through comments and via industry groups, such as the Interstate Natural Gas Association of America and the American Gas Association. PHMSA will in due course respond to the industry's questions and concerns and make its final ruling.

This article continues examination of the proposed changes to 49 CFR Part 192.

TRANSPORTATION

Corrosion control, evaluation

The annual cost associated with corrosion damage in the US of structural components is greater than the combined annual cost associated with natural disasters, including hurricanes, storms, floods, fires, and earthquakes.[1] Typical corrosion mechanisms include uniform corrosion, stress corrosion cracking, and pitting corrosion. The corrosion control measures in the current CFR are in the form of requirements regarding coatings, cathodic protection systems, and integrity assessments.

Implementing the new rules will require wide-ranging changes to the application of corrosion control measures, involving considerable assessment work. The sections most heavily affected are §192.319, 192.461, 192.465, 192.473, 192.478, 192.485, 192.493, Subpart O, and Appendix D.

Changes will involve additional requirements for assessing coating damage (§192.461), including immediately following new installation (§192.319). Operators will have to assess the integrity of the coating using DC voltage gradient or AC voltage gradient before backfill. A maximum timeframe for remediation of cathodic protection deficiencies and transmission will be established, and interrupted close interval surveys required, to determine the extent of the area with inadequate CP and confirm restoration (§192.465).

On transmission lines (it is still unclear if these rules apply to gathering lines) operators also will have to perform interference surveys on a periodic basis to detect electrical stray current (from both AC and DC interference), analyze results, and mitigate detrimental effects within 6 months of the survey (§192.473). The regulations do not clearly define either the frequency with which surveys will need to occur or whether all transmission pipe will have to be surveyed for interference.

Operators will further need to implement an internal corrosion program (twice each calendar year) to monitor and mitigate corrosive constituents in gas being transported (§192.478). Clarification is needed regarding where the gas stream and liquid quality should be monitored.

The bulk of the proposed changes will affect internal corrosion direct assessment (ICDA) and stress corrosion cracking direct assessment (SCCDA) programs. Under the new regulations, these programs would be defined by NACE SP0206-2006 and NACE SP0204-2008 for ICDA and SCCDA, respectively.

ICDA

The new rules will impose the following limitations on indirect inspection of internal corrosion: "[T]he operator must use pipeline specific data, exclusively. The use of assumed pipeline or operational data is prohibited." Here again, the operator will be required to consider the accuracy, reliability, and uncertainty of data, 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." The changes in the direct assessment portion are highly prescriptive when internal corrosion is found, requiring additional excavations at specific feature sites.

SCCDA

Most of §192.929 is redefined or added, meaning extensive changes to operators' SCCDA programs. The NACE SP0204-2008 standard provides the framework for this methodology, but the following factors must be analyzed as part of evaluation:

- 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 CP.
- Effects of cyclic loading conditions on the susceptibility and propagation of SCC in both high-pH and near-neutral-pH environments.
- The effects of variations in applied CP (such as overprotection, CP loss for extended periods, and high negative potentials).
- The effects of coatings that shield CP when disbonded from the pipe.
- Other factors affecting the mechanistic properties associated with SCC, including historical and current operating pressures, high-tensile residual stresses, flowing product temperatures, and the presence of sulfides.

The SCCDA plan must also include at least two above-ground surveys and a minimum of three direct examinations within the SCC segment. If SCC is detected the operator will be required to undertake extensive remediation and mitigation. The operator could elect to remove or sleeve the affected pipe, grind out the affected area, or perform a hydrotest according to the procedure specified in the new code. Any reduction in WT will have to be validated by ASME/ANSI B31G or RSTRENG, with remaining thickness sufficient to meet the design requirements of Subpart C. Post-assessment steps, in addition to the NACE requirements, must include a reassessment plan at an interval compliant to §192.939 and must consider:

- 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.
- Conditions conducive to creating the carbonate-bicarbonate environment.
- Conditions in the application (or loss) of CP that can create or exacerbate SCC.
- Operating temperature and pressure conditions, including operating stress levels on the pipe.
- Cyclic loading conditions.
- Mechanistic conditions influencing crack initiation and growth rates.
- Effects of interacting crack clusters.
- Sulfides.
- Disbonded coatings shielding CP from the pipe.

Implementing the SCCDA as written would entail considerable information, investigation, and follow-up actions.

Change management

Subpart O of 49 CFR 192 specifies the elements that a gas pipeline integrity management program must contain. Subparagraph (k) is being revised to specify that one of the required elements be "a management of change process as required by §192.13(d)." Section 192.13(d) is a proposed new section in Subpart A (General) requiring:

"Each operator of an onshore gas transmission pipeline must evaluate and mitigate, as necessary, 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."

The proposed §192.13(d) lists the elements that must be included in the management-of-change process. These elements are taken directly from ASME/ANSI B31.8S, Section 11, Subparagraph (a):

- Reason for change.
- Authority for approving changes.
- Analysis of implications.
- Acquisition of required work permits.
- Documentation.
- Communication of change to affected parties.
- Time limitations.
- Qualification of staff.

ASME/ANSI B31.8S, Section 11, Subparagraphs (b)-(h) provide further explanation and examples of these required elements.

The following industry publications provide additional guidance on management of change processes. They are not referenced by 49 CFR 192 and therefore are not needed to demonstrate compliance.

- API RP 1173, Pipeline Safety Management System Requirements.
- RC14001, Responsible Care Management System and Certification.
- PRCI IM-2-1, Facility Integrity Management Program Guidelines.
- Canadian Energy Pipeline Association, Facility Integrity Management Program Recommended Practice.

Recordkeeping clarification, expansion

Records management activities should be performed in compliance with all requirements arising from current business needs, the regulatory environment, and community expectations. The notice of proposed rulemaking (NPRM) proposes to modify §192.13(e) to require each operator to make and retain reliable, traceable, verifiable, and complete records that demonstrate compliance with 49 CFR Part 192 in accordance with Appendix A, Records Retention Schedule for Transmission Pipelines.

The Pipeline and Hazardous Materials Safety Administration (PHMSA) states: "Section 23 of the [2011 Pipeline Safety] Act requires the Secretary of Transportation to require verification of records used to establish maximum allowable operating pressure (MAOP) to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that an important aspect of compliance with this requirement is to assure that records that demonstrate compliance with Part 192 are complete and accurate. The proposed rule would add a new paragraph (e) that clearly articulates the requirements for records preparation and retention and requires that records be reliable, traceable, verifiable, and complete."[2]

PHMSA has not clearly defined what constitutes a reliable, traceable, verifiable, and complete record in the context of 49 CFR Part 192 as a whole. Generally, a reliable record is one in which the contents can be trusted as a full and accurate representation of the transactions, activities, or facts and can be depended on in the course of subsequent transactions or activities.[3] In the context of establishing MAOP, the National Transportation Safety Board (NTSB) and PHMSA have indicated before that reliable records are those that are traceable, verifiable, and complete.[4 5]

PHMSA defines these terms within this context as follows:

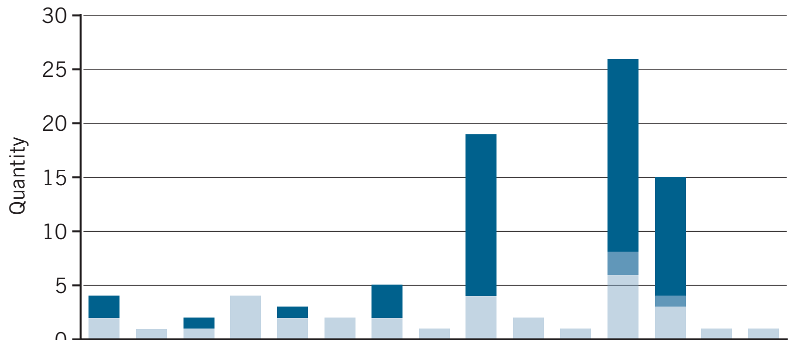
- Traceable records are those which can be clearly linked to original information about a pipeline segment or facility.
- Verifiable records are those in which information is confirmed by other complementary, but separate, documentation.
- Complete records are those in which the record is finalized as evidenced by a signature, date, or other appropriate marking.

It is unclear whether PHMSA intends to apply these definitions to Part 192 in its entirety or will issue revised definitions specific to the application section. It is also not clear whether PHMSA will issue formal criteria for demonstrating the reliability of one's records in accurately capturing the information intended.

Although §192.13(e) would add a significant number of new recordkeeping requirements throughout 49 CFR, the vast majority are compliance oriented in that they relate to documenting and

PROPOSED RECORD KEEPING REQUIREMENTS

FIG. 1

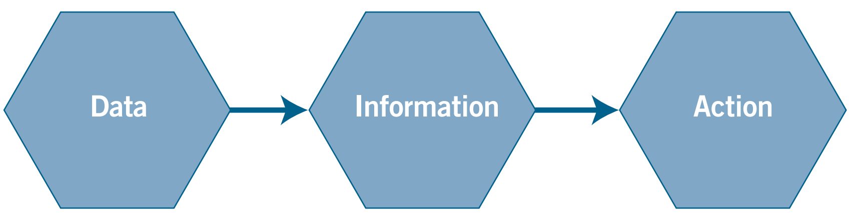


Section	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
New	2	1	1	4	1	2	3	1	15			18	11		
Clarification												2	1		
RTVC only	2		1		2		2		4	2	1	6	3	1	1

Source: NPRM, 2016

DATA MODERNIZATION STRATEGY

FIG. 2



- Identify data needs
- Define data collection mechanisms
- Define data storage system

- Store and display data to allow for analysis, trending, assessment
- Define, provide metrics

- Convert analysis, trends, metrics, into decisions and actions
- Establish priorities

retaining information for activities that operators must already perform under the existing rules. Most of these requirements apply to Subparts I (Corrosion Control), L (Operations), and M (Maintenance), as shown in Fig. 1.

Given the many changes proposed and the increased emphasis and scrutiny on recordkeeping, operators may want to perform a regulatory gap analysis to identify how these changes will affect existing operations. When properly maintained and structured, tools such as requirement matrixes can provide operators the means to quickly and efficiently identify impacted guidance documents when industry regulations are revised or reissued.

Operators may also want to consider performing a baseline audit of their existing records to assess the adequacy of their engineering records management program, including the quality assurance and control processes in place to ensure that any records compliance issues are readily detected and corrected. It is not uncommon for inadequate training and procedures to compromise the reliability of both hard copy and electronic records.

For some operators, these changes may present an opportunity to move toward a business model in which compliance records can be readily leveraged to enhance asset management programs. A key to effective asset management is the ability to transform data into well-informed actions (Fig. 2). Operators who make this transition will be able to make decisions and rate-case justification statements based on facts. They will also have a foundation for near real-time system performance monitoring, quantitative risk assessments, fitness-for-service evaluations, reliability-centered maintenance, and resource allocation optimization. OGJ

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