Pressure testing and recordkeeping: reconciling historic pipeline practices with new requirements

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THE NATIONAL Transportation Safety Board's recommendations to pipeline operators and regulators, based on their investigation of the 2010 San Bruno, California gas pipeline incident, has focused industry attention on validation of gas pipeline maximum operating pressures of pipelines installed prior to federal or state regulations. The industry is in the process of understanding the viability of continued current operation of "grandfathered" pipelines and pipelines that lack records necessary to give full confidence of the quality of installation. A full understanding of the implications requires knowledge of how industry practices and code requirements in the areas of pressure testing and recordkeeping have evolved over time.

This paper[1] explores these issues in gas pipeline standards and regulations, historically and currently, nationally and in the state of California. It is likely that similar considerations may develop in other states. The paper describes the evolution of pipeline pressure testing requirements, what records have been specifically required, how those records relate to establishing the maximum allowable operating pressure (MAOP) of a pipeline, why so-called "grandfathered" pipelines have existed, and the significance of recently articulated criteria for records accuracy.

THE INVESTIGATION BY the National Transportation Safety Board (NTSB) of the 2010 gas pipeline incident in San Bruno, California determined that the pipeline rupture originated in one of several short "pups" that was not manufactured in a manner consistent with known line pipe manufacturing processes. Who manufactured the pups, why they were manufactured as they were, how they came into the operator's possession, and how they came to be installed was not established conclusively and may never be known beyond speculation. Based on their findings, the NTSB issued recommendations to the industry to review its pipeline records to better understand whether they support their respective MAOPs, particularly for "grandfathered" pipelines operating in Class 3 and 4 locations and in high consequence areas (HCAs) in Class 1 and 2 locations.

In response, the California Public Utilities Commission (CPUC) issued Decision (D.)11-06-017 directing all operators of natural gas pipelines in the state of California to replace or pressure test all pipelines that have not been pressure tested to "modern standards."[2] This is interpreted to include all grandfathered pipelines, as well as pipelines having insufficient records to substantiate that a pressure test was conducted. Which pipelines must be included in the operator's testing plans is less clear than it at first seems, since pressure testing requirements and recordkeeping requirements have evolved over time. In the proceedings before the CPUC a broad spectrum of difficult questions have been raised, such as:

- Does a verified test to lesser performance and documentary requirements than the 1970 49 CFR 192, Subpart J acceptably qualify the MAOP?
- Could a probable test supported by incomplete or indirect documentation suffice?
- Is an operator "imprudent" for failing to assure an unbroken chain of documentation from a time prior to when specific recordkeeping requirements came into effect? What if the records loss occurs after recordkeeping requirements were in effect?

[1] Based substantially on Application No. 11-11-002, Rebuttal Testimony of Southern California Gas Company and San Diego Gas & Electric Company in Support of Proposed Natural Gas Pipeline Safety Enhancement Plan, Before the Public Utilities Commission of the State of California, prepared testimony of Michael J. Rosenfeld, July 18, 2012.

[2] http://docs.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/136948.htm

- Are complete pressure testing records necessary to operate a pipeline in a prudent and safe manner, and if not, should an operator then be held responsible for failing to maintain records intact, retrospectively?
- Is it possible to not follow voluntary standards while still remaining prudent?
- Do existing regulations acknowledge and accept the possibility of incomplete records?

Whether rate payers or shareholders should bear the burden of applying new criteria for MAOP validation of gas transmission pipelines is a current issue in California and depends on the answers to these and other questions. The authors are not aware of this issue arising in other states at this time, however, PHMSA is evaluating whether similar requirements may be appropriate for the interstate gas transmission pipeline system. It may be only a matter of time before the question of who pays for what arises outside of California.

As regulators and operators contemplate what criteria should apply retrospectively, and at whose expense any corrective action is taken, the history of practices with respect to pressure testing and recordkeeping should be recognized and accounted for. This paper is intended to provide information toward that objective.

Standards and regulations development

Evolutionary steps

The evolution of modern gas pipeline standards can be traced to the B31 Code for Pressure Piping, Standard B31.1, first published as a tentative standard by the American Standards Association (ASA), a predecessor to the American National Standards Institute (ANSI), with sponsorship of the American Society of Mechanical Engineers (ASME). This standard covered the materials, design, and fabrication of piping systems with industry-specific sections for power piping, gas and air piping, oil piping, and district heating piping. The scope of Section 2 covering gas and air piping systems included city gas distribution systems, and cross-country gas pipelines and compressor stations. ASA B31.1 was updated and republished in 1942, 1947, and 1951.

The gas pipeline industry desired to further develop the standard to better address the technical requirements for buried natural gas pipelines, which differ substantially from the technical issues associated with piping systems within power and process facilities that tended to dominate technical development of the standard. This desire was further stimulated by a widely publicized gas distribution system incident in Rochester, New York in 1950 and concern for a consequent regulatory response[3]. In response, Section 8 of the 1951 B31.1 addressing only natural gas pipelines was approved and published as a stand-alone document in 1952. Although it drew largely on the technical requirements for gas and air piping in Section 2 and selected fabrication details from Section 6 of the 1951 B31.1 standard, the publication separately from B31.1 provided the platform for further development of a more comprehensive pipeline-specific technical standard.

The 1955 edition of Section 8, designated B31.1.8, represented a significant technical advancement in requirements for natural gas transmission and distribution piping systems. It incorporated a risk-informed design basis in the form of a location class scheme based on the density of development near the pipeline, significantly more guidance relevant to the design and installation of cross-country transmission pipelines and gas distribution systems, and rigorous new pressure testing requirements. It was thought that a well-conceived technical standard for pipelines could be useful to

[3] Elder, L.L., “The History of the Gas Piping Standards/Technology Committee”, GPTC/GPSRC 25th Anniversary Meeting, July 17-20, 1995

state pipeline safety regulations[4]. Elements of the 1955 standard are still evident in the current edition. The standard was revised and republished as B31.8 in 1958, 1963, and 1968 prior to the issuance of pipeline safety regulations by Department of Transportation (DOT) in 1970. Addenda were issued in some years between editions. B31.8 continued to be revised and periodically republished from 1974 to the present time.

The CPUC enacted General Order 112 (GO 112) in 1961, specifying minimum rules for the design, construction, operation, and maintenance of natural gas pipelines within the state of California. Fourteen other states had also established regulations for natural gas pipelines by that time. GO 112 incorporated substantial portions of the 1958 edition of B31.8, omitted portions in conflict with CPUC requirements, and added language where necessary to accomplish its goals as the utilities regulator. The incorporation of suitable portions of B31.8 into GO 112 was consistent with ASA's purpose in publishing its standard. Subsequent issuances of GO 112 in 1964 and 1967 incorporated significant portions of the most-current edition of B31.8 until DOT issued its gas pipeline regulations in 1970. Subsequently, GO 112 incorporated DOT regulations.

In response to a significant gas pipeline incident in Natchitoches, LA in 1965, the Natural Gas Pipeline Safety Act (NGPSA) of 1968 authorized DOT to create the Office of Pipeline Safety (OPS, predecessor to the present Pipeline and Hazardous Materials Safety Administration, or PHMSA), enact interim safety standards within 3 months consisting of existing state safety standards, and issue federal pipeline safety regulations within 24 months. Interim regulations comprised of existing standards were imposed until complete regulations were adopted as Part 192, effective July 1, 1970. A review of the technical content of Part 192 shows a clear influence of B31.8, with revisions in language and additional content for clarity and enforcement. Part 192 does not make specific reference to B31.8 on most technical matters because it was the belief of the then-director of OPS that a regulation may be potentially compromised by referring to industry-developed standards[5].

The NGPSA also required the establishment of the Technical Pipeline Safety Standards Committee (TPSSC). The purpose of the TPSSC was to review all proposed pipeline regulations for "technical feasibility, reasonableness, and practicality"[6].

In 1970, by agreement with OPS, ASME began publishing language from Part 192 supplemented with practices from B31.8 and other sources to guide operators in meeting the regulatory requirements. The publication was prepared by the Gas Piping Standards Committee (GPSC) and known as the "GPSC Guide". In 1982, the administrative support was transferred to the American Gas Association (although it continued to be published by ASME), the committee name changed to the present Gas Piping Technology Committee (GPTC), and it acquired recognition as ANSI Z380[7].

Standards are not regulations

The foregoing discussion explains the origin of present-day regulations in contemporaneous industry-developed standards. Standards exist to provide technical guidance and promote uniformity in practices. In particular, ASME B31.8 was intended to be a statement of what is generally accepted to be good practice[8], written by engineers for an audience of other engineers, designers, managers, and regulators. Hence the standard cannot include practices that are not generally accepted even if they are superior, nor should it include practices that are considered unnecessary. The requirements set

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[4] Hough, F.A., "The Gas Industry has Approved its New Safety Code", Gas Magazine, November 1954.

[5] Jennings, W.C., "The Regulator's Handbook", June 1971.

[6] Federal Register, Vol. 35, No. 161, Wednesday, August 19, 1970, pg. 13256.

[7] Elder.

[8] Hough, F.A., "The New Gas Transmission and Distribution Piping Code (ASA B31 Section 8)", Gas Magazine, Series in 8 Parts, January through September 1955.

forth in B31.8 are considered adequate under normally-encountered conditions, while unusual conditions are not specifically provided for. Also, the standard is not law. The standard was intended to improve public safety through compliance by pipeline operators voluntarily and in good faith[9].

A regulation is a legally enforceable requirement, as a government response to a problem. Regulations are written by regulators for an audience of inspectors and the regulated entities, for the purpose of enforcement. The regulation embodied in Title 49 of the Code of Federal Regulations Part 192 (49 CFR 192) was intended to prescribe the level of performance that must be met, while leaving industry free to develop the specific means of meeting the prescribed level of performance. In other words[10], regulations prescribe "what" while industry standards describe "how".

Even though technical provisions in the regulations (GO 112 and 49 CFR 192) have their origins in technical provisions in the standard (B31.8), there are many areas in which the regulations and the standard do not agree, both historically and today. These include matters of pressure design, material properties, hydrostatic pressure test requirements, valve spacing, recordkeeping, and various elements of operation and maintenance.

History of gas pipeline pressure test requirements

Advent of hydrostatic testing

Hydrostatic pressure testing[11] is now a standard practice for commissioning a pipeline today but this was not always the case. The concept of pressure testing as a means of establishing the ability of pipe to safely contain pressure in operation was adopted from the vessel industry, which had begun to implement that practice prior to 1900. However, pressure testing a natural gas pipeline that is many miles long with water is much more difficult than filling a vessel with water; these differences posed serious challenges to early pipeline operators, for a couple of reasons. One is that the large quantity of clean water necessary to fill a cross-country pipeline was difficult to obtain and manage in any location and particularly so in dry-climate regions where many early large pipelines were constructed. The second problem was dewatering, since the methods and tools to accomplish that had yet to be developed. (This was also the case with other complications such as bleeding trapped air, rupture isolation/containment, and refilling or transferring test water from section to section.) Similar limitations affect gas distribution systems: the quantities of water required are still large, the networked nature of the systems complicates dewatering, and residual water in distribution piping is a problem for customers. Consequently, through the 1940s, if a pressure test was performed at all, it was usually accomplished using the transported commodity, natural gas in the case of gas pipelines, or crude oil or petroleum products in the case of liquid transmission pipelines. Owing to concerns for the consequences of a failure when testing with product (loss of product in the case of liquids, and loss of extensive quantities of pipe due to fracture propagation in the case of testing with natural gas), operators typically limited test pressures to between 5 psig and 50 psig above, or at most 10% above, their intended operating pressure[12,13,14,15].

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[9] Hough, 1954

[10] Jennings.

[11] "Hydrostatic testing" means conducting a pressure test of a pipe or vessel using water as the pressurizing medium. However, the term has often been used historically and today to refer to pressure testing using any fluid including gaseous media such as air, nitrogen, or natural gas. In this document, "hydrotesting" is used in the incorrect but colloquial form to indicate a pressure test using any fluid except where a distinction is made with respect to the test medium.

[12] Kiefner, J.F., "Section 4, Hydrostatic Testing", *GRI Guide for Locating and Using Pipeline Industry Research*, Prepared by Kiefner & Associates, Inc. for Gas Research Institute, GRI-00/0192.04, March 2001

The first large-scale use of proof testing long-distance gas pipelines with water was carried out by the Texas Eastern Transmission Corporation (TETCO) in 1950[16]. In 1947, TETCO acquired the two War Emergency Pipelines built to transport crude oil and fuel from Texas to New Jersey during World War II, and converted them to transport natural gas. TETCO experienced many service failures due to original pipe manufacturing defects that may have enlarged while in petroleum transportation service, and also due to corrosion because parts of the line were installed uncoated to save time. In 1950, TETCO completed an ambitious program to revalidate the integrity of the pipelines by pressure testing them with water to levels well above the MAOP and in some cases up to yielding. TETCO was able to do this because they had already developed cleaning pigs that were inserted into traps and propelled by gas pressure to sweep accumulated liquids out of the line as part of the process of converting the lines from liquid to gas[17]. Although they experienced hundreds of pipeline breaks during testing[18], the tested pipelines were reliable in subsequent years and portions of them are still in service today[19]. As a result of TETCO's experience, the industry performed scientific studies between 1953 and 1968 to better understand the benefits, limitations, and mechanics of hydrotesting[20],[21],[22]. Over time, other operators began to adopt the practice of pressure testing with water to higher stress levels than had previously been customary.

The evolution of test requirements for commissioning a new pipeline system as they pertain to transmission pipelines constructed from steel pipe is summarized briefly below. Testing requirements are not discussed herein for: low- and high-stress distribution piping, mains, and service lines; piping fabricated from plastic or cast iron pipe; testing for purposes of uprating; and testing to accommodate changes in location classes. The reason for omitting these requirements is they introduce significant complexity in details that are not central to the issue at hand. Figure 1 gives a timeline for major changes in pressure testing requirements.

B31.8 Standard, predecessors, and sequels

Two important eras can be defined with respect to pressure testing requirements in B31.8: pre-1955 and 1955-and-later, because the 1955 edition of the Code marks the first time that pressure testing a pipeline after construction was made a requirement to complying with the standard. The basis for this conclusion is discussed below.

ASA B31.1 Prior to 1955

Section 2 of the 1935 B31.1 defined two categories of pipe based on location: Division 1 piping was air or gas piping constructed within power plants, gas plants, or manufacturing plants, or within the boundaries of cities or villages; Division 2 piping was constructed in compressor stations, installed cross-country, or outside boundaries of cities or villages. Within both divisions, before installation,

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[13] Hough, 1955.

[14] McGehee, W.B., "Maximum Allowable Operating Pressure (MAOP) Background & History", Report for Gas Research Institute, March 5, 1998.

[15] [15] Shires, T.M. and Harrison, M.R., "Development of the B31.8 Code and Federal Pipeline Safety Regulations: Implications for Today's Natural Gas Pipeline System", GRI-98/0367.1, December 1998

[16] Castaneda, C.J., and Pratt, J.A., From Texas to the East: A Strategic History of Texas Eastern Corporation, Texas A&M University Press, 1993.

[17] Castaneda and Pratt

[18] Bergman, S.A., "Why Not Higher Operating Pressure for Lines Tested to 90% SMYS?", Pipeline and Gas Journal, December 1974

[19] Kiefner

[20] McGehee

[21] Kiefner

[22] Bergman

valves and fittings were to be "capable of withstanding a hydrostatic shell test" to designated pressures based on pressure rating classes similar to present-day pressure ratings for valves and flanged fittings. Pipe used in Division 1 service was also to be "capable of meeting the hydrostatic test requirements" contained in listed pipe product specifications, but pipe used in Division 2 was to be "subjected to and safely withstand a mill pressure test" in accordance with the pipe product specification (but not in excess of 90% of the yield point or yield strength of the material).

Some parties have suggested that the words "capable of withstanding" a pressure test to some level is means that a post-construction test was required. However, the Code used clearly different language to indicate an actual test requirement (e.g., pipe in the mill) as opposed to a capability for withstanding a test, which is a design requirement that is met through specifying an adequate combination of wall and metal strength. This is consistent with language used in contemporaneous standards for wrought fittings that also required that items be "capable of withstanding a pressure test to 1.5 times the working pressure", followed immediately by language stating that an actual test of each item was not required[23],[24]. This is further supported by recent interpretations of similar pressure capability language in PHMSA regulations[25].

After installation, Division 1 piping systems containing welded joints were to be "capable of withstanding a hydrostatic test" to 1.5 times the service pressure, with the test to be applied "where practical". It was further stated that "if a test is performed" welds were to be struck by hammer blows to jar them during the hydrostatic pressure test, something that can only be done with exposed piping, not a buried pipeline. With Division 2 piping, there were no pressure test requirements post-installation because such a test was deemed unnecessary: fittings were designed to be as strong as matching pipe, and pipe was required to have been tested at the mill. The working pressure was 80% of the pipe mill test pressure, or a percentage of the yield strength calculated as the seam joint efficiency factor divided by 1.4.

In no case was the working pressure established in the 1935 Code on the basis of a post-installation pressure test. The 1935 Code was understood to mean that testing of the pipe after installation was discretionary for Division 1 piping and not required for Division 2 piping. Most pipeline operators made this same interpretation until such time as testing became a clearly stated requirement in the 1955 edition[26].

The 1942 edition slightly revised the post-installation testing to requirements to be "capable of withstanding a test pressure" of 150% of the service pressure for Division 1 piping or 50 psig greater than the maximum service pressure for Division 2 piping. A test after installation "may be made with air or gas" which "need not exceed 120% of the maximum allowable working pressure" for Division 1 piping or "shall not exceed 120% of the maximum allowable working pressure" for Division 2 piping. Clearly, these test limits conflict with an interpretation that a requirement to be "capable of withstanding a pressure test" is synonymous with an actual requirement to carry out such a test, to 150% of the service pressure. The duration of a pressure test, if performed, was not specified. The Code stated that "where an actual internal pressure test is made" (implying the existence of places

[23] American Standards Association, "Steel Butt Welding Fittings", ASA B16.9, 1940.

[24] American Society for Testing and Materials, "Standard Specifications (Tentative) for Factory-Made Wrought Carbon-Steel and Carbon-Molybdenum-Steel Welding Fittings", ASTM A234, 1940.

[25] Gale, J.A., Office of Hazardous Materials Standards, PHMSA, letter to Fox, M., Chemical Accidents Reconstruction Services, Inc., response to inquiry concerning 49 CFR 173.306, Ref. No. 04-0203, March 18, 2005. "Section 173.306(a)(3)(ii) requires a metal aerosol container to be capable of withstanding without bursting a pressure of one-and-one-half times the pressure of the content at 130 degrees F. The [Hazardous Materials Regulations] do not specify a method for demonstrating that the container is capable of withstanding the specified pressure. You may demonstrate that the container meets the standard by testing or design specifications."

[26] Hough, 1955

where an "actual internal pressure test" was not made), the test pressure should be maintained for long enough to inspect the joints and connections. This requirement implies that the test's primary purpose was a leak test of flanged, threaded, or welded connections, not a proof of the strength of the pipe. Nowhere were working pressures established on the basis of a post-installation test. They were based on the mill test or an engineering calculation.

The 1947 Addendum to the 1942 B31.1 standard did not change the testing requirements for gas and air piping. The 1951 B31.1 standard slightly revised the post-installation testing provision to read "Where an internal fluid pressure test is made, it shall not exceed" 150% of the maximum allowable working pressure for Division 1 piping, and for Division 2 piping, 120% of or 50 psig greater than the maximum allowable working pressure, whichever was greater. The language still only required a capability for withstanding a test, not the performance of an actual test. If a test was performed using any fluid (liquid or gaseous), the maximum test level was limited, and no minimum test duration was prescribed other than that it be long enough to inspect joints and connections for leaks.

With the 1952 stand-alone gas-only Code, the "Division 1" and "Division 2" designations were replaced with description of the systems in §807(c)(2)(a) and §807(c)(1)(a), respectively. Pressure testing requirements were found in Chapter 5, "Requirements after installation" and were identical to the 1951 Code. However, for cross-country pipelines working pressures did depend on whether a post-installation test was performed. For pipelines installed prior to 1952, the allowed working pressure was either 80% of the pipe mill test pressure or a maximum of 72% of the yield strength ("Y") multiplied by a joint efficiency factor ("E"). For steel pipe outside of compressor stations, the allowed working pressure was either 80% of the pipe mill test pressure or 60% of Y times E for pipe not tested after installation, or 85% of Y times E for pipe tested after installation. Working pressure limits dependent upon whether a post-installation test was performed conclusively indicates that a post-installation test was not a requirement.

B31.8 Post-1955

The 1955 Code introduced the concept of 4 location class factors based on density of land development adjacent to the pipeline, each with different maximum allowable operating stress levels, and different pressure test requirements following installation. The precise definitions of the classes in terms of building or dwelling counts and the dimensions of the reference area were somewhat different than today, but the intended meanings of the classes were the same as today (e.g. Class 1 being rural, and so on) and the allowed operating stresses were also the same.

Testing requirements were stated in §841.3 "Testing after construction". All mains and services were to be tested, except tie-ins where individual test sections were eventually joined after testing. This was the first time in the gas piping standard that testing after installation became a firm requirement, but no minimum test duration was specified. The design requirement for a capability to withstand a pressure test was moved to Chapter 3 "Piping System Components and Fabrication Requirements", §831 "Piping System Components", where components were to be designed to withstand the system pressure test without failure, leakage, or impairment of their serviceability. Moving the "capability to withstand" language to Chapter 3 further substantiates the fact that a post-construction test was not intended or required by that wording.

Pressure test requirements were given in §841.4 "Test requirements". All pipelines and mains to be operated at a hoop stress of 30% or more of the specified minimum yield strength (SMYS) "shall be given a field test to prove strength after construction and before being placed in operation". Piping installed in Class 1 areas was to be tested with air or gas to 1.1 times the maximum operating pressure or hydrostatically tested to at least 1.1 times the maximum operating pressure; piping installed in Class 2 areas was to be tested with air to 1.25 times the maximum operating pressure or hydrostatically tested to at least 1.25 times the maximum operating pressure; and piping installed in

Class 3 and 4 areas was to be hydrostatically tested to at least 1.4 times the maximum operating pressure.

The hydrotest requirement for Class 3 and 4 piping was waived if the ground temperature at the time of the test was or might fall below a temperature of 32 F, or water of satisfactory quality was not available in sufficient quantity. In that case, an air test to 1.1 times the maximum operating pressure could be performed and the test pressure ratio of 1.4 did not apply. Air testing of Class 3 and 4 pipe was allowed in any case, provided strict hoop stress limits were observed, the pipe was not operated at more than 80% of the test pressure, and the pipe had a seam joint efficiency factor of 1.00.

Paragraph §841.5 "Safety during tests" advised the user to give due regard to the safety of employees and the public during pressure tests. When air or gas is the test medium, steps were required to remove persons not involved in conducting the test when the test hoop stress level exceeds 50% SMYS.

Pressure test requirements in the 1958, 1963, 1967, 1968, 1975, and 1982 standards and their addenda were the same as in the 1955 standard.

The 1984 Addenda to the 1982 edition specified that the pressure test of all piping intended to operate at hoop stress levels of 30% SMYS or greater be held for a minimum duration of 2 hours. This was the first occurrence of a specified minimum test duration in B31.8. Test levels were the same as previously. The pressure test requirements in the 1986 edition were the same as the 1984 Addenda.

The 1989 standard introduced a new operating stress level in excess of the traditional maximum operating stress level of 72% SMYS in Class 1, up to a maximum operating stress of 80% SMYS. Pipe in this category was referred to as Class 1, Division 1, and was to be pressure tested to a minimum stress level of 100% SMYS, with water as the only permitted test fluid. The traditional maximum operating stress of 72% SMYS was referred to as Class 1, Division 2. The same test requirements applied for Class 1, Division 2, and for Classes 2, 3, and 4 as in previous editions. The requirements from the 1989 edition remained unchanged in the 1992, 1995, 1999, 2003, and 2007 editions.

Important revisions were made to the pressure testing requirements with the 2010 edition. The minimum test ratio for Class 1, Division 2 pipe (with a maximum operating stress level up to 72% SMYS) was raised to 1.25, regardless of test medium, and the minimum test ratio for Class 3 and 4 piping was raised to 1.50. Also, significant additional guidance on test planning, execution, and risk mitigation is provided.

CPUC General Order 112 and Sequels

The CPUC introduced regulations governing the design, construction, operation, and maintenance of natural gas pipelines within the state of California under General Order (GO) 112, first issued in 1961. The pressure testing requirements in GO 112 are discussed below. Of course, a year other than 1961 may represent a regulatory threshold in other states.

CPUC General Order 112 incorporated significant portions of the 1958 B31.8 standard, with certain changes to the pressure testing requirements. Among those changes were: the pressure testing requirements were extended to pipe operating at hoop stresses of 20% or more of SMYS (rather than 30% or more of SMYS), the test margin for Class 1 pipelines was increased to 1.25, the test margins for Class 3 and 4 pipelines were increased to 1.5, and the test pressure was required to be maintained until it was stabilized and for a period of not less than 1 hour.

GO 112-A and GO 112-B were published in 1964 and 1967, respectively. The requirements on pressure testing were the same as those in 1961.

Following the issuance of 49 CFR 192, the 1971 GO 112-C replaced content from B31.8 with content from Part 192 with some additional requirements. The content from Part 192, Subpart J – Test Requirements, was incorporated verbatim. The 1979 GO 112-D incorporated the content from Part 192 issued in 1978. Since Subpart J remained relatively static in subsequent years, few changes in actual requirements occurred in GO 112.

49 CFR 192

The first full set of federal pipeline regulations were issued in 1970. Subpart J – Test Requirements, §192.501 through §192.517 set forth requirements for pressure testing of pipelines after construction. An important new requirement relative to those contained in preceding or contemporaneous editions of B31.8 or GO 112 was §192.505(c) stipulating maintaining the strength test pressure for at least 8 hours. As originally proposed, the specified minimum test duration was 24 consecutive hours, a practice that was observed by some but not all pipeline operators. This was reduced to 8 hours on the recommendation of the TPSSC because there was no evidence that a longer test was a superior test[27].

Aside from limitations based on maximum hoop stress levels, maximum allowable operating pressure was based on dividing the pressure test by a minimum specified factor, given in Subpart L – Operations, Clause 192.619(a)(2)(ii). For pipe installed after November 11, 1970, test pressure ratios were 1.1, 1.25, and 1.5 in Classes 1, 2, and 3 or 4, respectively. For pipe installed and tested prior to November 12, 1970, the test ratio for Classes 3 and 4 was 1.4, based on the requirements in the interim Federal standard between 1968 and 1970, which were the same as B31.8, and based on B31.8 being the de facto national standard prior to 1968 (except in California and perhaps a few other states).

These requirements for testing after construction have remained static in subsequent years.

Grandfathered pipelines

The term "grandfathered pipelines" refers to those pipelines for which the operating pressure was established on the basis of operating history rather than pressure testing in accordance with Subpart L. The origin and basis are described in the Preamble to the first full issuance of Title 49 – Transportation published in the Federal Register[28].

In the original proposal for Part 192, no recognition was given for piping installed prior to 1955[29] on the basis of very loose testing requirements, and for piping already operating at hoop stress levels greater than 72% SMYS. The Federal Power Commission (FPC) wrote to OPS pointing out that there were thousands of miles of pipeline already in service, installed in accordance with prevailing standards and practices, that could not continue operating at their then-current levels and comply with the proposed regulations. The FPC also stated that based on a review of the operating records of interstate pipelines, no improvement in safety would be gained by reducing the operating pressures of existing pipelines "which have been proven to be capable of withstanding present operating pressures through actual operation." In response, OPS included a "grandfather" clause to permit

[27] Hough, 1955

[28] Fed. Reg., pg. 13248-13276

[29] In its comments to the original docket, the TPSSC referred to 1952 as the first year that the ASME B31.1.8 gave minimum test pressures. However, that new test requirement occurred in 1955, not 1952. The TPSSC comments are interpreted accordingly herein.

continued operation of pipelines at the highest operating pressure the pipeline had experienced in service during the 5 years preceding July 1, 1970 (even if the pipe had previously been subjected to a hydrostatic pressure test to qualify a higher MAOP but the pipe had not operated at that level during the specified 5-year interval).

GO 112 already had set a regulatory precedent for the grandfathering of untested pipelines. Gas pipelines placed in service after July 1, 1961 were required to be pressure tested, but those installed before that date were exempted from pressure test requirements[30]. The CPUC was likely guided by provisions in §804.6 of the 1955 B31.1.8 and its sequels that the standard was not intended to be applied retroactively to existing facilities insofar as design, installation, establishing the operating pressure, and testing were concerned. Consistent with these exemptions, the concept that new or evolving requirements concerning materials, design, construction, and the establishment of the MAOP are not retroactive to existing facilities that are already in operation was recognized in the federal pipeline regulations from the outset. This concept is embodied in §192.13 and is fully expressed in the discussion of the retroactive effect on existing pipelines in the Preamble to Part 192[31].

History of recordkeeping requirements

Recordkeeping requirements prior to 1955

Recordkeeping requirements specified in engineering standards for gas pipeline prior to 1955 were few and focused on welding. The 1935 B31.1 standard required employers of welders to maintain records of their welding operators showing dates of employment, results of welding tests, and their assigned identifying mark. (Welders were required to stamp their identifying mark adjacent to welds they made on pipe.) The 1942 B31.1 standard, Appendix I, Part I required that records of welding procedure qualification testing and copies of the record for each qualified welder were to be kept by the manufacturer or contractor. No record retention period was specified, and no other recordkeeping requirements were expressed.

No provisions or requirements for recordkeeping of any kind dealing with welding or installation were specified in the 1951 B31.1. Similarly, none were given in the 1952 B31.1, Section 8 in its entirety.

It would be reasonable to expect that a variety of documents related to the design and construction of a pipeline facility be retained long-term. However, retention of technical documents was not addressed by the engineering standards of the day. It was generally thought that a copy of the specifications under which the pipeline was built (and supplemented by commercial documents, e.g. contracts and purchase orders) would generally be adequate to provide evidence of the work that was done[32].

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[30] CPUC, Rulemaking 11-02-019, Findings of Fact No. 5, pg. 27.

[31] Fed. Reg., pg. 13250, on the subject of the retroactive effect on existing pipelines, quotes the Natural Gas Pipeline Safety Act, Section 3(b): "Not later than 24 months after the enactment of this Act, and from time to time thereafter, the Secretary shall, by order, establish minimum Federal safety standards for the transportation of gas and pipeline facilities. Such standards may apply to the design, installation, inspection, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities. Standards affecting the design, installation, construction, initial inspection and initial testing shall not be applicable to pipeline facilities in existence on the date such standards are adopted."

[32] Hough, 1955

Recordkeeping requirements 1955 to 1961

The 1955 B31.1.8 Chapter II "Welding" required that records of welding procedure qualification tests be retained for as long as the welding procedure is in use. Further, the pipeline operator or contractor (presumably whoever employed the welders) was required, during construction, to maintain a record of the welders qualified, their dates of employment, and test results.

Chapter IV "Design, Installation, and Testing" required maintaining records showing the type of fluid used for pressure testing and the test pressure of pipelines that operate at a hoop stress of 30% or more of SMYS. The specified retention period was the useful life of the facility. This recordkeeping requirement was not stated under general testing provisions applicable to all pipelines, nor under subsequent paragraphs that presented separate pressure test requirements for pipe operating at less than 30% of SMYS but more than 100 psig, leak test requirements for pipe operating at 100 psig or more, or leak test requirements for pipe operating at less than 100 psig, respectively. Thus, an operator might reasonably not have retained records for tests performed in accordance with those paragraphs.

The 1955 edition was the first B31 piping standard to extend its scope beyond design, construction, and commissioning of the piping system to include operation and maintenance. Accordingly, additional recordkeeping language was introduced in Chapter V, "Operating and Maintenance Procedures". "Basic requirements" therein stated that "each operating company having gas transmission or distribution facilities … shall: (a) Have a plan covering operating and maintenance procedures…(c) Keep records necessary to administer the plan properly." Further, records "should" be made of pipeline inspections for external or internal corrosion, listing several items of potential interest, and records "should" be made covering leaks and repairs. In addition, leakage survey records, line patrol records and other records relating to routine or unusual inspections "should" be kept on file as long as the section of line remains in service. The operator was required to have plans for inspecting pipe-type and bottle-type gas holders, and to keep records detailing the inspection and test work done and the results.

The terms "shall" and "should" were used throughout B31.1.8 and its sequels. "Shall" is understood to mean an action is required, while "should" is understood to mean an action is recommended but not required. Records adequate to effectively execute the pipeline operation and maintenance were required, but specific records were merely recommended and what was actually required was left to the operator. The possibility was not precluded that data different than or in addition to what the standard said "should" be recorded might be necessary in order to fulfill the requirement to "keep records necessary to administer" the operation and maintenance plan. Note also that the Code has historically given leave to not follow specific requirements where the operator can show by experience, testing, or analysis that an alternative is safe and reliable[33]. An operator could conceivably set forth a position that maintaining some kinds of records is unnecessary based on experience.

Recordkeeping requirements 1961 to 1970

The 1958, 1963, and 1968 editions of ASME B31.8 did not differ from the 1955 edition with respect to recordkeeping. The 1968 edition included certain enhancements such as the weld inspection requirements similar to those introduced by the 1961 GO 112 but without the accompanying weld inspection recordkeeping requirement. On the other hand, the corrosion inspection and leak investigation recordkeeping provisions became required, not recommended.

[33] This includes but is not limited to: materials and equipment selection, fittings and components design, above-ground piping design, longitudinal stresses in buried pipelines, valve spacing, and cathodic protection criteria.

California General Order 112 of 1961 incorporated most if not all of the 1958 B31.8 standard, with added requirements to better meet the objectives of the CPUC, for clarification, and for enforcement. Some important additions involved recordkeeping. GO 112 added minimum welding inspections based on location class and stipulated that a record be made of the results of the tests and the inspection method used. The requirements for pressure testing of pipe that operates at 30% or more of SMYS was extended downward to pipe operating at 20% or more of SMYS. This change in scope included the pressure test recordkeeping requirements, which consisted only of the test fluid and test pressure per §841.417. In Chapter V, recommended patrols and corrosion inspections were made mandatory, and recommended records of corrosion inspections and leak investigations became required.

A Chapter VI "Records" was added consisting entirely of CPUC-added language. Clause §301.1 therein stated that "the responsibility for maintenance of necessary records to establish that compliance with these rules has been accomplished rests with the utility. Such records shall be available for inspection at all times by the Commission…" In other words, the utility must maintain sufficient records to be able to prove on demand that the utility is complying with all of the rules. This could include design calculations, material procurement records, and a broad range of construction and installation inspection data, in addition to the operation and maintenance activities described above, and could well have required more recordkeeping than was the case before GO 112. Also, the specifications for materials and equipment, installation, testing, and fabrication were required to be maintained by the utility.

A Chapter VII "Reports" was also added that required reporting to CPUC 30 days in advance of any proposed new installation, major reconstruction, or change in MAOP. Specific information to be reported to the CPUC included the purpose or reason for the activity, specifications concerning pipe to be installed, the MAOP, and the test parameters to be used.

GO 112-A of 1964 and GO 112-B of 1967 added no new recordkeeping requirements.

Recordkeeping requirements post-1970

Complete federal safety standards for gas pipelines were introduced in 1970. Although some technical content was based on the 1968 edition of B31.8, the regulatory provisions went well beyond B31.8 in terms of inspections and recordkeeping. All provisions were required, not merely recommended ("shall", not "should"). Moreover, many of these requirements exceeded those in effect in GO 112 at that time. These are briefly discussed below.

- Subpart E – Welding: §192.243(f), where nondestructive testing (i.e., radiography) of welds is performed, a record is required showing the number of girth welds made, the number tested, the number rejected, and their disposition by location (e.g., milepost), for the life of the pipeline. Also §192.225(c), requires a record of the details of each qualification of a welding procedure, to be retained for as long as the procedure is used.
- Subpart J – Test Requirements: §192.517, a record is required of each test performed on pipelines operating at a hoop stress of 30% or more of SMYS or above 100 psig but below 30% of SMYS. The record must indicate the following 7 items: (1) the names of the operator, the responsible employee, and the test company (if any); (2) the test medium used; (3) the test pressure; (4) the test duration; (5) pressure readings; (6) elevation variations if they are significant; and (7) leaks or failures. Such records must be retained for the useful life of the facility.
- Subpart K – Uprating: §192.553(b), a record is required of each investigation (e.g., review of the design, and operating and maintenance history), work done, and each pressure test

in connection with the uprate. The record must be retained for the life of the uprated segment.

- Subpart L – Operations: §192.619(a) sets forth criteria for establishing the MAOP, as the lowest of the design pressure of the weakest components or pipe based on specified attributes, the pressure obtained by dividing the post-construction test pressure by a specified factor, the highest actual operating pressure during 5 years preceding July 1, 1970, for furnace butt-welded pipe a pressure equal to 60% of the mill test pressure, for other pipe a pressure equal to 85% of the highest test pressure the pipe experienced in the field or pipe mill, or the maximum safe pressure determined in consideration of the condition and operating history of the pipeline.
- Subpart M – Maintenance: §192.709, a record is required of each leak discovered, repair made, line break, leak survey, line patrol, and inspection of transmission pipelines for as long as the line remains in service. Records have to be retained at least until the next round of inspections (e.g., 5 years).
- Numerous other activities (sampling of odorant, valve maintenance, vault maintenance, distribution leakage surveys, and others) must occur at specified periodic intervals. No recordkeeping was specified in connection with those activities.

The 1970 issuance of Part 192 added Subpart I on corrosion control, which required installation and criteria for the cathodic protection (CP) of buried steel pipelines, periodic monitoring of the effectiveness of the CP system, monitoring of internal corrosion, and monitoring of atmospheric corrosion. Recordkeeping requirements as of July 31, 1972 are discussed below.

- Subpart I – Corrosion Control: §192.491(a), each operator was required to maintain records or maps showing the location of cathodically protected pipe, CP facilities (e.g., rectifiers or anodes), and other structures bonded to the pipe. Also §192.491(b), each record or map from (a) plus records of each test or inspection of the CP system in sufficient detail to show adequacy of corrosion control were required to be retained as long as the facility is in service.

Important and extensive new recordkeeping requirements were put in place to support operator qualification (OQ) in 1999, integrity management planning (IMP) for transmission pipelines in high consequence areas (HCAs) in 2004, and distribution system IMP in 2009, as discussed below.

- Subpart N – Qualification of Pipeline Personnel: §192.807, requires the operator to maintain qualifications of personnel performing covered tasks. The qualification records must include identification of the individuals, the covered tasks each individual is qualified for, the dates of qualification, and the qualification method. The records must be maintained while the person is performing the covered task and for 5 years after.
- Subpart O – Gas Transmission Pipeline Integrity Management: §192.947, requires the operator to maintain records demonstrating compliance to Subpart O. The required items listed are (a) a written integrity management plan, (b) documents supporting the threat identification and risk assessment, (c) a written baseline assessment plan (BAP), (d) documents supporting each decision, analysis or process of each element of the BAP and IMP, (e) personnel training program and records, (f) prioritized assessment mitigation schedule, (g) documents supporting the Direct Assessment (DA) plan, (h) documents supporting the Confirmatory Direct Assessment (CDA) plan, and (i) verification of notifications made to OPS or any state regulator as required by Subpart O.
- Subpart P – Distribution Pipeline Integrity Management: §192.1011, requires the operator to maintain records that demonstrate compliance to the requirements of Subpart P, for at least 10 years. The records must include any superseded copies of the IMP.

Clearly, the regulations are punctuated by several major new additions to recordkeeping requirements, and today's recordkeeping requirements cannot be presumed to have applied at all times prior to the introduction of new requirements. A timeline of introduction of major recordkeeping requirements is shown in Figure 2.

Prudence and policy

Unbroken chain of documentation not the rule

The practical significance of the "grandfather" rule was that it was not necessary for an existing pipeline already in service to have been pressure tested to the minimum specified ratio of the MAOP. In fact, clause §192.619 offered four possible alternatives for establishing the MAOP:

- §192.619(a)(1) recognized the design pressure of the weakest component in accordance with Subparts C and D. In this case the MAOP would be based on manufacturer's component pressure ratings or engineering calculations using specified material strength and wall thickness.
- §192.619(a)(3) recognized the highest pressure to which the pipeline had been subjected during the 5 years preceding July 1, 1970.
- §192.619(a)(4) recognized 85% of the highest test pressure to which the pipe had been subjected, either in the pipe mill or in the field. If no field test was documented, the mill test would govern. The operator could determine the pipe mill test pressure from the pipe product specification.
- §192.619(a)(5) allowed the operator to determine the maximum safe pressure considering the history of the segment, known corrosion, and actual operating pressure. This might be used, for example, with an uncoated pipeline that had experienced general wall thinning due to corrosion. (It is notable that this language existed prior to the use of in-line inspection for conducting integrity assessment, so an operator might not have had complete information about the extent of corrosion.)

None of the above methods for establishing the MAOP necessarily required documentation of a prior post-installation pressure test. In fact, the method given in clause (a)(3) requires knowing no information about the specified grade or wall thickness of the pipe. That these alternative methods of establishing MAOP were allowed indicates that OPS accepted that records of testing or of pipe physical attributes were not always available. In particular, an operator was not prohibited from using clause (a)(3) even if a test had been performed and test records had been lost for some reason. These alternatives have been in Part 192 from 1970 to today, so OPS/PHMSA has since 1970 accepted that not all records need necessarily be present, or if present, need necessarily be complete or represent an unbroken chain of traceability.

Can an operator be "prudent" while missing records?

It is not uncommon for pipeline operators to have incomplete or inaccurate data about attributes of portions of their pipeline systems, including specified pipe material grades, specified nominal wall thicknesses, seam types, pipe manufacturers, coating types, flange or valve pressure classes, installation dates, construction specifications, welding procedures, pressure tests, corrosion control, and historic operating pressures.

The likelihood of records being incomplete increases with the age of the system, particularly with systems built prior to 1970 when the more-extensive records requirements of Part 192 came into effect. Nationwide, 37% of natural gas transmission pipelines now in service was installed before 1960, and 61% was installed before 1970[34], thus a sizable proportion of existing pipelines was

[34] http://www.phmsa.dot.gov/pipeline/library/data-stats

installed at a time when only minimal provisions for recordkeeping were found in standards and regulations. While the likelihood of gaps in the data increases with age, compromised data exist in systems built in many eras, including those built after 1970. Whether a lack of certain documents constitutes violation of regulations or indicates operator imprudence has become central to whether shareholders or rate payers pay for costly retesting or replacement of pipe.

There are many innocuous causes for loss of records including: an individual not recognizing the importance of a document or collection of documents, change of facility ownership, loss event (fire, flood), clerical mishandling, or misplacement in offsite storage, to list a few. Certainly back-up copies in one form or another can offset the loss of originals, but consider that photocopy technology was not widely available until the mid-1960s, perhaps after some original documents were already lost, and the back-up process is not without risk either[35].

Loss of useful records for any reason is not desirable, but past failure to preserve records does not necessarily imply operator imprudence or irresponsibility, neither does operating a pipeline while gaps exist in some records. Not all records are important to safely operating a pipeline day-to-day once the primary purpose of the record has been satisfied; prudence is exercised in making good choices with the information available. Consider that a pressure test of a pipeline following construction had been performed and that all stakeholders (owner, state or federal regulator, lender, insurer) were satisfied that the pipeline had been properly designed, constructed, and commissioned. The MAOP is entered into a ledger, a memo stating the MAOP is issued to control room operator, pressure control set points are confirmed, and operating procedures are updated. Consider next that the actual pressure test records become lost some years later. How does the loss of that record affect any of the numerous activities a prudent operator is obliged to carry out day after day, such as: controlling pressure within established set points, marking the line for excavators, conducting damage prevention and public education programs, periodically testing valves, performing leakage surveys, repairing leaks, conducting line surveillance, maintaining cathodic protection, or training operations personnel, to name a few? The answer is that it does not. Once the MAOP has been correctly established using any one of the allowed methods, those records have little bearing on day-to-day operation of the line.

The foregoing discussion is not meant to suggest that all records losses or data gaps are inconsequential. In fact, accurate and readily available data of some kinds are essential for safe and efficient operation. The authors support the industry's efforts to respond to the San Bruno incident by evaluating the accuracy of its records. There is value in good records, however, the authors also believe that more has been made of the role of recordkeeping as a cause of that incident than may have been warranted. The conclusion that the incorrect identification of the pup that originated the failure as "30-inch seamless" in the pipe inventory database would have led any operator to enact a series of decisions culminating in the removal of the pipe decades after its installation stretches credibility. The industry, including regulators and other stakeholders, should contemplate whether any amount of retrospective records analysis can offer complete protection against "unknown unknowns", particularly where they originated many decades ago[36]. That argues in favor of the CPUC Decision to require replacement or retesting where adequate test records are lacking. It also leans toward ratepayers carrying the financial burden of achieving the added assurance provided by

[35] An anecdote reported to the authors was an occasion where a clerical worker, instructed to photocopy hydrostatic test records, first separated the pressure charts from the test report forms which had been stapled together into separate piles, irreversibly breaking the link between pressure records and test segments. In another case, documents sent by an operator to a third-party long-term storage facility were misplaced by the storage contractor.

[36] Certainly intensive QA auditing efforts soon after construction can potentially reveal incorrect actions or wrongdoing.

pipe replacement or retesting unless it can be shown that an operator's behavior went well beyond the lack of historic documentation.

Gaps in data that validate the MAOP severely limit an operator's options for addressing a change in location class, pressure uprate, or request for regulatory waiver or special permit, which is as it should be. Data quality also has implications for integrity management. Certain elements of an IMP, notably the integrity threat identification and risk assessment tasks, are facilitated by having reasonably complete and accurate historical and technical data. ASME B31.8S recognizes that data important or useful to these tasks may be missing: §4.2.1 "Data Requirements: Prescriptive Integrity Management Programs" states that if listed data elements relevant to an integrity threat are not available, the integrity threat must be assumed to apply; §4.4 "Data Collection, Review, and Analysis" states that unavailability of data cannot be used to justify excluding an integrity threat; §5.9 "Data Collection for Risk Assessment" advises that if significant data are not available, the risk model may need to be modified based on an analysis of the impact of the data being unavailable; Appendix A, the paragraph "Gathering, reviewing, and Integrating Data" states that where the operator is missing data, conservative assumptions shall be used with the risk assessment or the segment shall be prioritized higher for each integrity threat listed. Part 192, Subpart O, §192.917 requires the operator to perform integrity threat identification and risk assessment in accordance with B31.8S, Sections 4 and 5, respectively, which incorporate the above provisions concerning how to compensate for unavailable data. By referencing these sections, the regulations clearly contemplate that data important to an IMP may be unavailable.

"Traceable, verifiable, and complete" represents new requirements on recordkeeping

It has been suggested in the course of public debate that the criteria for document reliability, being "traceable, verifiable, and complete" do not represent new standards for the quality of natural gas pipeline records. While the attributes of "traceable, verifiable, and complete" are certainly desirable, and reasonably expected in modern times, they are not standardized thresholds for data quality for pipelines of all eras, and have no basis in regulation. They represent new documentary criteria.

The words "traceable, verifiable, and complete" appear nowhere in any issuances of B31.8, GO 112, or 49 CFR Part 192 prior to SR P-10-2. The words, as applied to documents related to the design, construction, or operation of a natural gas pipeline, did not originate with the federal pipeline regulatory agency, the CPUC, or any other state pipeline regulatory agency. The terminology "traceable, verifiable, and complete", as used in connection with gas pipelines, originated with the NTSB's Safety Recommendation (SR) P-10-2 issued to Pacific Gas and Electric (PG&E)[37]. The NTSB recommendation that records "should" (not "shall" or "must") be traceable, verifiable, and complete applied to "all as-built drawings, alignment sheets, and specifications, and all design, construction, inspection, testing, maintenance, and other related records…relating to pipeline system components, such as pipe segments, valves, fittings, and weld seams for Pacific Gas and Electric Company natural gas transmission lines in class 3 and class 4 locations and class 1 and class 2 high consequence areas that have not had a maximum allowable operating pressure established through prior hydrostatic testing". The NTSB did not extend the recommendation to all pipeline facilities in all locations, nor to any facilities anywhere that have in fact been pressure tested.

In the gas pipeline context, the terms originated with NTSB as stated above, though NTSB may have assimilated the terms from applications outside the pipeline industry. The NTSB is not a regulatory agency, but rather an independent agency of the United States government that has no responsibility for writing regulation and no powers of regulatory enforcement. Based on accident investigations that it is authorized to perform, the Board offers opinions and recommendations that may or may not

[37] NTSB, Safety Recommendation (SR) P-10-2, January 3, 2011.

be observed[38]. The NTSB recommendations almost certainly were not made in consultation with PHMSA[39].

Shortly after issuance of SR P-10-2, PHMSA issued ADB-2011-01 advising operators that records they rely on for establishing the MAOP "must be reliable" and that the records "shall be traceable, verifiable, and complete"[40]. It took PHMSA another 16 months to develop guidance to the industry as to how to interpret the terminology in order to satisfy the new requirements[41]. In the meantime, the industry attempted to articulate what was necessary to meet these requirements by issuing white papers[42] and developing individual company processes in the hope of meeting the regulator's unspoken criteria. No guidance was found in the "GPTC Guide"[43], a widely used reference guide to the interpretation of and compliance to Part 192. The fact that no guidance could be found in any common external publication is consistent with the position that "traceable, verifiable, and complete" represented new criteria.

From ADB-2012-06, "traceable" records are tied to original documents. It should not be surprising that some documents that predated 1961 or even 1970 might not have been retained if there was no regulatory requirement to retain them. It is also possible, with the passage of time, for original documents to become lost through any of the possible loss mechanisms described above. In these or similar circumstances, it becomes impossible to meet the "traceable" test. While not optimal, losses of traceability are not uncommon.

- "Verifiable" records are those in which data is confirmed by other separate documentation. ADB-2012-06 appears to require that any record used to establish the MAOP must be confirmed by another record. Nowhere in the historical or current regulatory language reviewed above does agreement between multiple data sources appear as a requirement.

- "Complete" records are finalized by a signature or date. ADB-2012-06 gives, as an example: "a complete pressure testing record should identify a specific segment of pipe, who conducted the test, the duration of the test, the test medium, temperatures, accurate pressure readings, and elevation information as applicable." This example lists two items that are not specified in §192.517, namely the specific segment of pipe, and temperatures. Thus meeting PHMSA's requirements for recordkeeping since 1970 actually does not meet the test for completeness in ADB-2012-06, so clearly a new requirement has been imposed.

The language of SR P-10-2 is clearly made in reference to "grandfathered pipelines" that are now in Class 3 or 4 areas. As explained in Part D above, gaps in documentation could well occur in connection with many "grandfathered pipelines". Therefore, the notion that the criteria of SR P-10-2 represent thresholds of data reliability that have always existed in regulations is inconsistent with established fact.

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[38] The NTSB's reports are not admissible in court, 49 USC 1154(b): "No part of a report of the Board, related to an accident or an investigation of an accident, may be admitted into evidence or used in a civil action for damages resulting from a matter mentioned in the report"; although its investigators' factual reports are, 49 USC 835.

[39] 49 USC 1131: "The Board shall provide for appropriate participation by other departments, agencies, or instrumentalities in the investigation. However, those departments, agencies, or instrumentalities may not participate in the decision of the Board about the probable cause of the accident."

[40] PHMSA Advisory Bulletin, "Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation", ADB-2011-01.

[41] PHMSA Advisory Bulletin, "Pipeline Safety: Verification of Records", ADB-2012-06.

[42] American Gas Association, "Industry Guidance on Records Review for Re-affirming Transmission Pipeline MAOPs", October 2011.

[43] "GPTC Guide for Gas Transmission and Distribution Piping Systems", ANSI Z380.1, various years

What does this mean for policy?

Costs for California natural gas pipeline operators to perform hydrostatic testing and/or replacement of hundreds of miles of "grandfathered" pipeline, some located in congested areas, in order to comply with CPUC's Decision have been projected to be $1.2 billion for Sempra and about $1.3 billion for PG&E[44]. The question to be settled, in public debate or hearings, is how to share the enormous cost between shareholders and rate payers in an equitable manner.

The authors do not dispute the need to modernize the nation's pipeline infrastructure, verify the integrity of "grandfathered" pipelines as well as any other category of pipeline, and enhance data as well as is practical in order to manage risk as well as is practical. We believe that pipeline operators should be accountable for failures to meet regulatory obligations. However, we further believe that regulators should not give in to the temptation (perhaps driven by public pressure) to penalize operators retrospectively for practices that previously were not considered deficient as judged by standards of the era. Past practices must be gauged against an accurate and reasonable interpretation of historic standards, regulations, and accepted practices. Moreover, proceedings to establish financial penalties for past failure to comply with regulations should be separated from ratemaking proceedings designed to regulate future behavior[45]. When weighing financial penalties, consideration should also be given to the intensity of the regulator's past focus on regulatory provisions deemed in retrospect to have been contravened. (In other words, if the regulatory violation was a failure to comply with recordkeeping requirements, did the regulator recognize an infraction in the past? If so, what was done about it? If not, has a reasonable "statute of limitations" rendered it moot?) Finally, customers should pay rates that fully reflect the cost of providing the goods or services[46]. Rates should therefore reflect the cost of complying with new regulatory requirements. This includes the cost of retesting or replacing pipe not thought to meet modern standards of integrity, where those activities are necessitated by new regulations.

Figure 3 below presents a matrix of compliance in terms of pressure test activity versus time. The time scale is divided between Pre-1955, 1955 to 1961, 1961 to 1970, and Post-1970. (A threshold year other than 1961 may apply in other states.) The pressure test activities are grouped as "No test", "Probably tested but no records", "Partial test records available", and "Full test records available". Situations where the indicated combination of testing history and documentary completeness are likely to comply with applicable requirements of the era, or not, are suggested in the matrix. Other situations fall in a gray area that should be evaluated making a reasonable accounting of circumstances. The burden of revalidating confidence in the existing pipeline system is likely to be tied in part to the perceived degree of compliance to requirements of the era. Figure 3 can serve as a guide to that process.

Summary and conclusions

This paper reviewed the history of industry standards and regulatory requirements in the areas of hydrostatic pressure testing and recordkeeping. The review shows that hydrostatic pressure testing after construction was not required by applicable industry standards (ASME B31.8) until 1955. The technology for pressure testing cross-country gas pipelines was not developed until 1950. Prior to 1955, operating pressure was established by the pipe mill test or an engineering calculation. Post-

[44] www.dra.ca.gov

[45] [45] CPUC Rulemaking 11-02-019, Exhibit 21, Pacific Gas and Electric, Pipeline Safety Enhancement Plan (Implementation Plan), prepared testimony of Susan F. Tierney, "Principles to Align Safety and Regulatory Ratemaking Policy", February 28, 2012.

[46] Tierney.

construction tests were discretionary, and generally for detecting leaks at flanged or welded joints above ground. Industry standards were referenced by some state regulations (e.g., GO 112 in 1961) until the issuance of federal safety regulations in 1970.

Recordkeeping requirements began with welding quality control. In 1955, hydrostatic test records and those necessary for executing the operator's O&M plan were required. Of test records, only test fluid and test pressure were required, and then that requirement only pertained to pipelines operating at a hoop stress of 30% or more of SMYS. It was thought at that time that engineering specifications and commercial documents were adequate to demonstrate practices. Additional recordkeeping requirements were imposed by federal safety regulations in 1970, including for hydrostatic pressure testing.

When federal regulations were issued in 1970, several options were available for establishing the MAOP of existing ("grandfathered") pipelines that did not rely on a documented post-construction pressure test. This establishes that for the past 50 years, the regulators have accepted that documents supporting the MAOP could be incomplete. In that context, the tests set forth in ADB-2012-06 represent new standards that should not be used to judge whether an operator has complied with prior standards for that purpose as part of the ratemaking process.

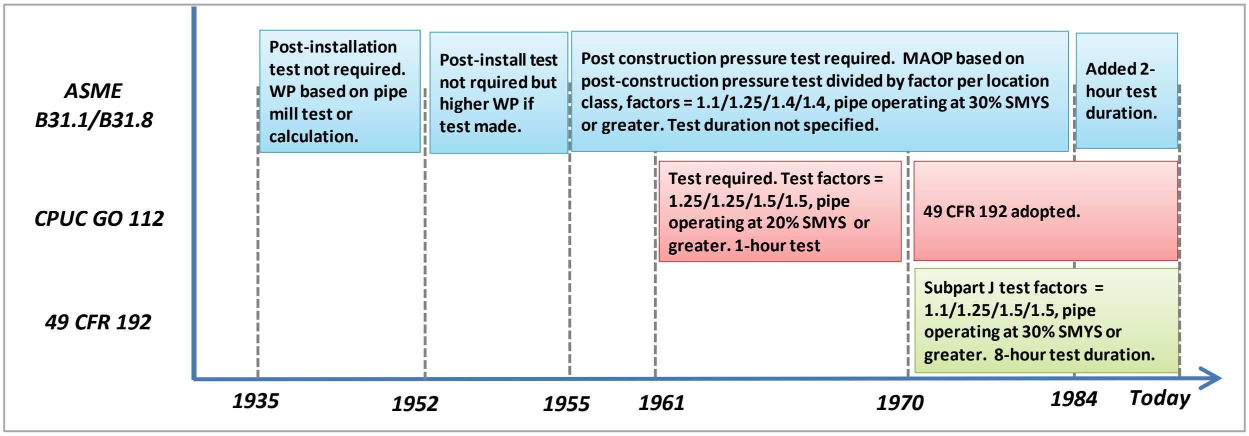

Fig.1. Timeline of pipeline hydrostatic pressure test requirements.

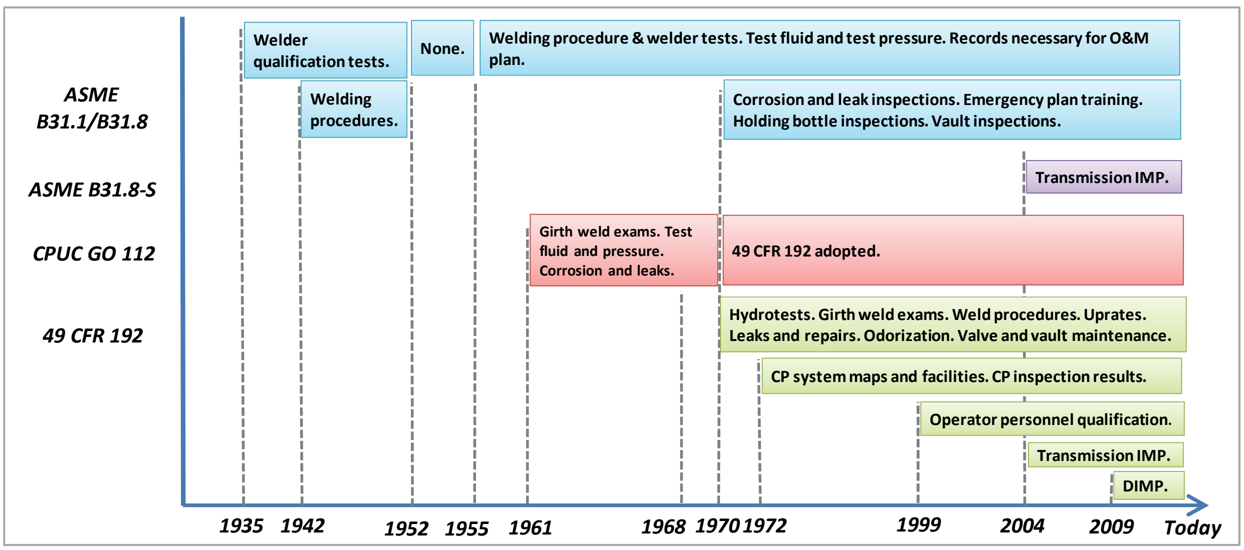

Fig.2. Timeline of significant recordkeeping requirements.

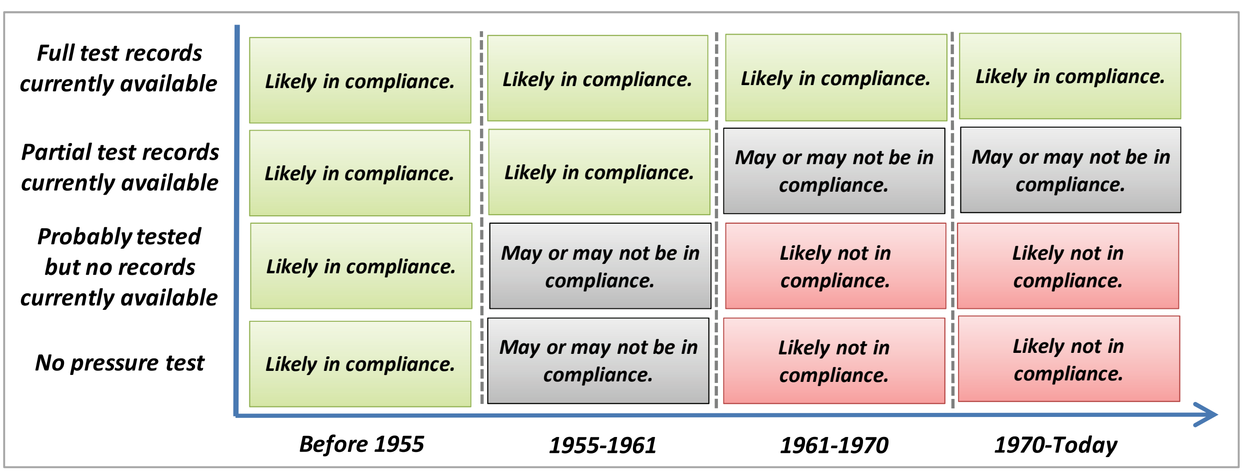

Fig.3. Pressure test compliance matrix.