Hydrotesting in the Modern World – What Are We looking for?

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Abstract

Modern hydrostatic testing is often seen as a “check the box” for new construction. While required by code for most pipelines, in the fast-paced culture of the “get ‘er done” world, is pipeline hydro testing still needed? With so many technological advances, can we remove this requirement? In the mind of the inspector, are discrepancies: “just temperature,” “not regulated,” “doesn’t matter?” This presentation is designed for the inspector signing off their name on a hydrostatic test. Do you believe that this pipeline is safe and that it is not leaking? This paper will discuss what is obvious, what is not so obvious, and why You, as inspector or engineer, should verify all the data. By the way, what are you signing for? What should you be concerned about? How will the new regulations impact the future of hydro testing?

Scope – why did hydro testing start, and why is it still done?

Hydrostatic pressure testing, the precursor to the commissioning of pipelines for nearly a century, began being conducted as part of a recommended practice in 1928. By 1941, the American Society of Mechanical Engineers (ASME) published ASME B31.1, a voluntary code standard, adding hydro testing as a recommended practice that became widely adopted by the 1960’s. A widely publicized gas distribution incident in Rochester, New York, in 1950 stimulated the desire to develop further gas pipeline standards, resulting in the development and publication of ASME B31.8.[1] It was not until the 1970s that the code of federal regulations mandated pressure testing for commissioning and re-commissioning pipelines in response to a significant gas pipeline incident in Los Angeles in 1965. The original purpose of the pressure test was to ensure that the pipeline could contain the operating pressures and was not leaking at the time of construction. Before the 1970s, most line pipes were limited to lower pressures and even mill tests rarely exceeded 85% of the Specified Minimum Yield Strength (SMYS).

In response to multiple failures, most notably the San Bruno disaster in 2010, the National Transportation Safety Board (NTSB) made recommendations to Congress and the Pipeline Hazardous Materials Administration (PHMSA) to increase the requirements in the code of federal regulations to prevent future failures. Some of the requirements that PHMSA included in its update to 49 CFR 192 included requiring an operator to verify the properties of pipeline materials that are traceable, verifiable, and complete. PHMSA included a requirement to re-confirm the maximum allowable operating pressure (MAOP) if the records necessary to establish the MAOP are not traceable, verifiable, and complete and the pipeline is located in a high consequence area (HCA) or a class 3 or 4 location using one of five methods which include pressure testing. A newly constructed pipeline undergoes multiple inspections utilizing an array of technologies today, including mill hydro tests, Ultrasonic inspections of the seam, mill inspections, coating inspections, X-rays, and sometimes Ultrasonic inspections of the girth welds, jeeping, and in-line inspections, sometimes using multiple technologies. Is the pre-commissioning hydrostatic test just to check the box that the pipeline is complete? Are failures under hydrostatic tests of new pipelines unheard of? Why are pressure tests still required?

[1] Pressure testing and recordkeeping: reconciling historic pipeline practices with new requirements, Michael J Rosenfeld and Rick W Gailing, Kiefner and Associates, Southern California Gas Co, PPIMC 2013

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The American Petroleum Institute (API) recently updated API RP 1110 Recommended Practice for the Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids, or Carbon Dioxide to the seventh edition in December 2022. Included were updates to account for technology advances as well as references to newer recommendations and editions of other pipeline-recommended practices such as API 1176 Recommended Practice for the Management of Pipeline Cracking (2016) and API 1179 Hydrostatic Testing as an Integrity Management Tool (2019). Clearly, the pipeline industry finds value and needs to continue utilizing hydrostatic testing to manage pipeline threats. What has been discovered, though, is that even with all the new technologies and extensive inspections of new pipes, new pipelines occasionally fail under hydrostatic testing. In some cases, the failures may be difficult to detect due to the size of the failed defect.

Hydrostatic pressure testing is a subset of pressure testing requirements. Other pressure testing types may include inert gas such as Nitrogen, Air (pneumatic), or even natural gas. Hydrostatic pressure tests are preferred in most cases as it is safer to test with water, which rapidly de-pressurizes in the event of a failure, than gas.[2] Additionally, the potential energy stored in compressible gases can be catastrophic when released, resulting in far more damage to the environment surrounding the pipe failure location.

Details of modern pipe hydrostatic testing failures

Traditionally, hydrostatic failures of the pipeline long seam have been relegated to pre-1970s pipelines with low-frequency electric resistance welds. However, recent failures of modern high-frequency electric resistance welded pipe where lack of fusion of the long seam, particularly near the girth weld, is resulting in failures under hydrostatic test. These defects tend to be unnoticed during mill testing due to the proximity to the ends of the joint where the seal for the mill test would be placed, and this same section is not inspected by the ultrasonic inspection of the majority of the pipe during the mill test process. Other pipeline failures during testing include a new pipeline under hydrostatic testing circa 2010 that failed from incomplete welding of the girth weld. An operator also described a case discovered during a review of construction records circa 1990 construction of failure of a long seam during the hydro test. There are likely other cases of hydrostatic test failures of this type that have not been recorded or widely reported, as it is very typical in the industry to replace the bad joint and move on to another test without further investigating the cause of the failure or making much more than a note of a re-test due to a bad joint failing the test. In most cases, none of the data or records of the failure are kept for further analysis or evaluation, let alone securing the failed pipe for root cause failure investigation.

Most recently, an operator investigated an in-service leak of a 10-year-old (circa 2012) pipeline that the investigation found to have been caused by a lack of fusion of the long seam. The cases described in this paper indicate that although less common, pipeline failures still occur during commissioning hydrostatic tests, and there may even exist today very small leaks that were not detected during hydrostatic testing and, due to the nature of current leak detection methods, may yet be discovered in the future. The existence of some of these defects means that a population of defects exists that did not fail and may grow to failure in the future. Due to the nature of these very small defects, those failures that happen or currently exist as very small leaks may go undetected for many years into the future. Pipeline operators and inspection personnel who are not expecting or looking for these small

[2] ASME B31.8-2018 Section 841.3

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leaks leave themselves open to being caught off guard by sudden failures or investigations into the original records. The decision is made to accept the hydrostatic test as successful when there may be indications that were dismissed in a rush to complete the project and commission the pipeline. The following are more detailed cases of pipeline hydrostatic test failures that demonstrate the continued need to hydrostatically test pipelines.

The first case is a 2012 installed 10.75-inch pipeline with 0.219” wall thickness and grade X42 seam failure. No failure analysis was performed, but the pipe was confirmed to have been manufactured in Turkey based on available MTRs for the construction of this pipeline. The photo, shown in Figure 1, and the note of the failure were found in pipeline construction files during the review for data integration purposes in 2020.

Figure 1. Case 1 – Seam failure of 2012 installed pipe during hydrostatic test

The second case is a 2015 installation of 20-inch 0.375” wall thickness and grade X65 that failed under hydrostatic test, and the failed pipe was sent for laboratory investigation of the failure. The pipe ERW seam was incompletely subjected to post-weld heat treatment as required by API 5LX. The pipe was manufactured in the US. The pipe failure was initiated by a lack of fusion of the long seam within ¼” of the girth weld. It is noted in the failure report that portions of the seam on this joint had post-weld heat treatment. Figure 2 shows photos of the failure.

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(a)

(b)

Figure 2(a-b). Case 2 – Investigative failure photo (a) Seam failure of 2015 installed pipe under hydrostatic test (b)

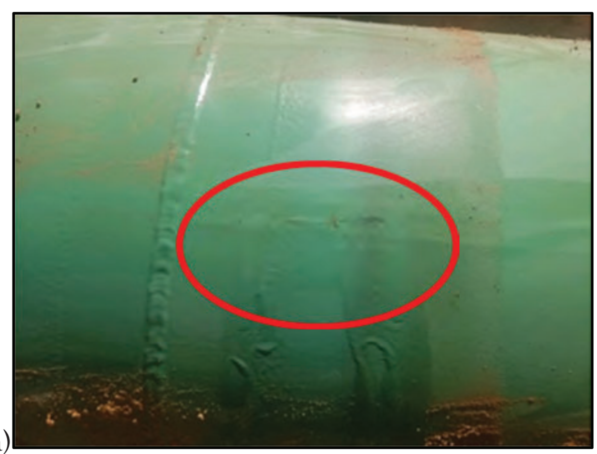
The third case involved a slightly more unusual type of failure; a newer pipeline was installed in 2019 API 5LX 8.625" with 0.250 wall thickness and grade X52. The pipeline failed under a new construction hydrostatic test by an erosion-corrosion mechanism. Results from the investigation of this failure noted significant debris and sand were found in and near the failure point. This caused a substantial concentration of high-velocity material erosion occurring during the pipeline fill, resulting in hydro test failure due to the loss of steel at the site, as shown in Figure 3 below.

(a)

(b)

Figure 3(a-b). Case 3 – 2019 erosion corrosion failure during commissioning hydrostatic test

The fourth case involved a newer pipeline installed in 2019: API 5LX 20" with 0.375" wall thickness and grade X65 that failed from a lack of fusion of the long seam. The pipe was manufactured in the US. In this case, the failure initiated within 3" of the girth weld and was discovered when the pipe failed to maintain the maximum required pressure. However, the leak would seal up, and the pipeline would stop losing pressure when the maximum pressure was lowered from the test pressure to begin searching for the leak. This leak was challenging to locate due to the small size of the defect, resulting in a very low leak rate.



(a)

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(b) 

Figure 4(a-b). Case 4 – Lack of Fusion Long Seam failure of 2019 installed pipe

What is the inspector's role?

The inspector's role is to observe and record how and what data is being collected, and understanding what the data tells the inspector is critical. The best practices involve reporting the data to an engineer for analysis to confirm expected versus actual pressure differences throughout the test. Temperatures have a significant impact on the hydrostatic test pressures. Collecting temperature readings using digital and encoded data from insulated points is critical to ensuring that the measurements are representative of the actual temperature of the test media, usually water. Stabilizing the water temperatures is necessary to allow the hot squeeze and warmer fill water to cool and match the pipe temperature. When insufficient time is allowed for stabilization, small leaks may be hidden within the pressure losses that are attributed to temperature equalization. The location where the temperature probes are placed is critical. The best practice involves burying the temperature probe in the ground, attached to the pipe, away from the test and squeeze sites. Recording the temperatures using accurate digital recorders to at least one-tenth of one degree is essential for monitoring temperature trends and identifying if pressure changes are consistent throughout the test. Recording the pressure-volume (PV) plot during squeeze-up is very helpful to size a suspected leak during the test or understand if the test pressures are causing yielding of the pipe components.[3] When designing a test and during initial pressurization, the inspector should understand how much air may be trapped in the system, as this can affect the pressurization and equalization of the system. Additionally, significant air in the pipeline system can result in a safety hazard.

The pipeline inspector should observe and record any anomalies before, during, and after the test. A 4-hour test only needs visual observation that the pipe and components are not leaking and that the minimum pressure level is held throughout the duration of the test. Regulators look very closely at the full 8-hour test and examine it for evidence of "spinning" the chart. Pressurization charts should include a 15-minute before the start of and after the completion of the test to make it easy to see that the test was held over 8 hours. Short holds during the pressurization process allow for the examination of pipe and fittings for leakage. Some leaks and ruptures are pronounced loss of pressure, sometimes instantaneously. Others are not so obvious.

[3] PR-430-153706 Guidelines for the Use of Hydrostatic Testing as an Integrity Management Tool, PRCI Project IM-3E, Jan 6, 2016

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During the pressure test, is the pressure rising? If so, is it enough to hide a leak? A one psig per hour leak rate is easily masked by a couple of degrees in temperature increase. Did the pressure rise sufficiently to match the expected growth that would be expected from a temperature increase? Engineers have built calculators to take the inputs of pressure, temperature, length of pipe buried, and length of pipe exposed to calculate the expected change in volume due to temperature effects. Often, companies develop procedures around the allowable difference between the computed and actual pressure or volume changes to guide the engineer on what is or is not acceptable. The ambient temperature's impact on the pressure depends on how much pipe is exposed. Did the inspector record the footage of the exposed pipe? Is there enough significant footage of the pipe to impact the test pressures? Consideration should be made to insulate or protect considerable lengths of exposed pipe from temperature effects. Is there an identified trend in pressures? Leaks can be very small and not very obvious if so. Pressure loss can be slow and relatively minor. The following example, Figure 5, is only an approximate ten psi loss; however, note that the temperatures are slightly climbing. Using a Pressure-Volume Plot from the initial squeeze-up can allow the inspector to estimate the volume of liquid lost into the environment if a leak exists and determine the rate of fluid lost per hour.

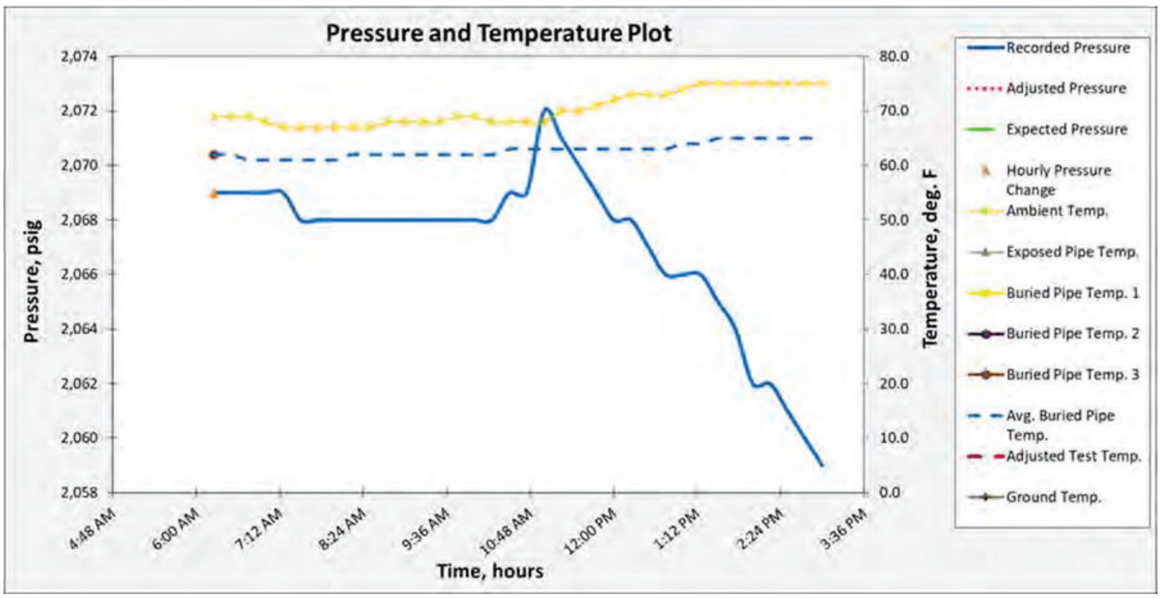

Figure 5. Example pressure-volume plot

The public is no longer tolerant of pipeline leaks after commissioning. The costs associated with dealing with the aftermath of a hydrocarbon leak can be substantial. A lack of fusion of the long seam leak is challenging to observe and find. Significant ambient temperature changes further exacerbate this or if the hydro test water was not given sufficient time to thermally stabilize. Identifying a small leak can take considerable time in large-volume segments.

When a pipeline segment is pressurized to high-stress levels, rapid depressurization of the pipeline can shock the pipe and cause a stable defect to suddenly become unstable and fail. It is entirely unobservable due to blowing down, and the subsequent leak may not be discovered until later after significant environmental damage. The pipeline depressurization should occur gradually following the new guidance in API Recommended Practice 1110, seventh edition, updated in December 2022. The inspector's signature affirms that all required information is accurately and completely recorded. An accepted test means that the test was successful and the pipeline was not leaking at the time of

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the test. Including an engineer's signature is best practice and some companies now require it. An engineering analysis should be utilized to confirm that the expected versus actual pressure differences are justified from an engineering standpoint; incomplete data can make this analysis impossible to complete.

Detailed data commonly missed or not recorded include the pipeline segment elevation, location of the pressure test recording equipment and elevation, pipe wall thickness and grade, the pressure vs volume plots, legible names of the personnel performing or recording the test, and signatures. This results in records that are not complete. An example of a hydrostatic test with missing or conflicting information recorded during the MAOP establishment process for Type C gas gathering pipelines is shown in Figures 6 through 9. Note the summary information provided in **Figure 6**b, the lack of completed information on observed pressures, and that temperature increases while pressure decreases throughout the test in **Figure 7**.

(a)

Sct	Length		Outside Dia		Wall Thick		Grade
1	15,175	ft	20.000	in	0.375	in	X-65
2	126	ft	20.000	in	0.500	in	X-60

(b)

Test Duration 8 hours		Min Pressure 1817 psi	Max Pressure 1897 psi
Test 1 of 1		Hold Press	300 psi
Medium Water		Hold Time	12 hrs
Fill Vol	gals	Press Vol	1806 gals

Figure 6. (a-b) Hydrostatic Test Summary Page Excerpt

Test Started:	05/05/18	12:30 PM	at	1851	psi	66	F soil	Product Service:	Natural Gas
Test Completed:	05/05/18	8:30 PM	at	1834	psi	67	F soil	Pressure Rate:	34 gpm
Max Observed Pressure:		psi	Min Observed Pressure:				psi	Total Duration:	8 hrs 41 mins
Test Successful?	yes	Repressures	0	Volume	0	gals	Bleeds 0	Volume	0 gals

Figure 7. Hydrostatic Test Summary Page Excerpt

Notice that the detailed information in Figures 8 and 9 does not match the summary information; pipe temperature is recorded as unchanged, soil temperatures decreased then increased, and ambient temperatures increased most of the test with a slight decrease at the end. Pipeline pressures only decreased over the entire 8-hour test.

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Date	Local Time	Pipeline Press	Pipe or Soil Temperature	Ambient Temperature	Comments
05/04/18	5:00 PM	0			Start fill
05/04/18	9:20 PM	110			End fill
05/04/18	9:51 PM	300			Shut in line and leave for 12 hour stabilization.
05/05/18	10:05 AM	226			Install new chart and open instruments to line pressure.
05/05/18	10:15 AM	226			Start pressure
05/05/18	10:33 AM	925			Stop pressure, start 30 min hold. 772 gallons
05/05/18	11:03 AM	924			End 30 min hold
05/05/18	11:05 AM	924			Start pressure
05/05/18	11:25 AM	1480			Stop pressure, start 30 min hold. 619 gallons
05/05/18	11:55 AM	1479			End 30 min hold.
05/05/18	11:56 AM	1479			Start pressure
05/05/18	12:1[illegible] PM	1852			Stop pressure, check for leaks, 415 gallons
05/05/18	12:15 PM	1852			No visible leaks, start 15 min pre test hold.
05/05/18	12:30 PM	1851	69-66	64	Begin 8 hour test
05/05/18	12:45 PM	1851	69-66	65	Partly cloudy, warm
05/05/18	1:00 PM	1850	69-65	65	Exposed pipe on far end partially under water.
05/05/18	1:15 PM	1850	69-65	66	
05/05/18	1:30 PM	1849	69-65	67	No visible leaks.
05/05/18	1:45 PM	1849	69-65	67	
05/05/18	2:00 PM	1848	69-65	67	
05/05/18	2:15 PM	1848	69-65	67	
05/05/18	2:30 PM	1847	69-65	67	No visible leaks
05/05/18	2:45 PM	1847	69-65	68	
05/05/18	3:00 PM	1846	69-65	68	
05/05/18	3:15 PM	1846	69-65	68	
05/05/18	3:30 PM	1845	69-65	69	No visible leaks
05/05/18	3:45 PM	1845	69-65	69	
05/05/18	4:00 PM	1844	69-64	69	Continued on page 2.

Figure 8. Hydrostatic Test Log Excerpt

Date	Local Time	Pipeline Press	Pipe or Soil Temperature	Ambient Temperature	Comments
05/05/18	4:15 PM	1843	69-64	69	Continued from page 1
05/05/18	4:30 PM	1843	69-64	69	No visible leaks
05/05/18	4:45 PM	1842	69-65	69	
05/05/18	5:00 PM	1842	69-65	69	
05/05/18	5:15 PM	1841	69-65	69	
05/05/18	5:30 PM	1841	69-65	69	No visible leaks
05/05/18	5:45 PM	1840	69-65	69	
05/05/18	6:00 PM	1840	69-65	69	
05/05/18	6:15 PM	1839	69-64	69	
05/05/18	6:30 PM	1838	69-63	68	No visible leaks
05/05/18	6:45 PM	1838	69-62	68	
05/05/18	7:00 PM	1837	69-63	67	
05/05/18	7:15 PM	1837	69-63	67	
05/05/18	7:30 PM	1836	69-64	67	No visible leaks
05/05/18	7:45 PM	1836	69-64	66	
05/05/18	8:00 PM	1835	69-65	66	
05/05/18	8:15 PM	1834	69-66	65	
05/05/18	8:30 PM	1834	69-67	65	End 8 hour test
05/05/18	8:45 PM	[illegible]			End 15 min rollover

Figure 9. Hydrostatic Test Log Page 2 Excerpt

The above is an example of an incomplete record not signed by company personnel, and no engineering analysis was conducted to confirm that the pipeline pressure loss was unrelated to a leak. As an inspector, one should ensure that all required signatures are gathered upon completion of the test. If an incident occurs in the future, complete records of all required signatures are best practice to support that the test was completed, data recorded accurately, and accepted by multiple individuals that the test was successful. Operators should review hydrostatic test records, particularly for unregulated or partially regulated pipelines, to determine if potential leaks may exist on these pipelines.

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Similar but different code requirements for gas and liquid

The minimums of each federal code (gas vs. liquid) differ slightly. As of 2019, for 49 CFR 192 (gas), the operator must now make and retain a record of each test containing the following for the useful life of the pipeline.

- Operators name,
- Name of the employee who planned the test
- Name of the test company(s)
- Test pressure
- Test duration
- Test medium used (water, air, nitrogen)
- Pressure recording charts or other records of pressure readings (i.e., handwritten, digital)
- Significant elevation variations
- Leaks and failures noted and their disposition (what happened and why and result)
- Note service lines, plastic lines, and pipelines operating less than 100 psi (Retain for 5 years)

For 49 CFR 195, the requirements include the above plus the following:

- Test instrument calibration data
- The date and time of the test
- Minimum test pressure
- Temperature of the test medium or pipe during the test period
- Description of the facility tested and the test apparatus
- An explanation of any pressure discontinuities, including test failures that appear on the pressure recording charts

Spike hydrostatic testing – a special case.

Spike hydrostatic testing is used as an integrity management tool whereby the test pressure is raised higher than required for a short time period. The purpose is to grow defects that are near the failure threshold to a failure state and then check for leaks while holding the pressure at a lower level. Special requirements now apply when performing this test on a pipeline subject to 49 CFR 192, which is operated greater than 30% SMYS. The test must use water, and after the test pressure stabilizes within the first two hours, the hydro test pressure must be raised (spiked) to a minimum of 1.5 times MAOP or 100% SMYS, whichever is lower. This pressure must be held for a minimum of 15 minutes. Additionally, the test pressure must be held at or above the baseline pressure for at least 8 hours, where the baseline is specified by the MAOP or alternative MAOP requirements.

At the time of this paper, PHMSA has not yet implemented similar requirements in 49 CFR 195 for liquid pipelines. However, it is expected that in early 2024, additional rulemaking for the liquid pipeline industry will be proposed, and this may be included in that rulemaking.

Additionally, API has produced a technical report, API TR 1179 Hydrostatic Testing as an Integrity Management Tool, First Edition, May 2019, that includes special considerations for utilizing hydrostatic testing as an integrity management tool and describes three levels of hydrostatic testing:

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a qualifying test for establishing MAOP or maximum operating pressure (MOP), respectively, a high-pressure integrity test where the test pressure is higher than required to establish MAOP or MOP and is utilized to manage an integrity threat by increasing the safety factor between operational pressures and the failure pressure of potential defects, and lastly, a spike hydro test that includes a brief (15 to 30 minute) spike test pressure at the beginning of the test, followed by an 8-hour pressure test at an at least 5% lower pressure[4] to evaluate the pressure trends for potential leaks. A spike hydro test is typically utilized to manage a cracking threat. API 1179, used in conjunction with API 1176 Recommended Practice for the Management of Pipeline Cracking and API 1110 Hydrostatic Testing, represent a compendium of best practices in hydrostatic testing of pipelines. PRCI report PR-000-20COMP-R05 titled, “Research Compendium – Pressure Testing of Pipelines,” contains abstracts of past PRCI research on the subject of pressure testing and is meant to be used as a knowledge resource for the industry.

Conclusions

In conclusion, hydro testing is not a “check-the-box” activity. A hydrostatic test is still utilized to confirm the ability of the pipeline to contain the pressure levels intended for the transportation of gases and liquids. Failures of new pipe joints still occur even with the advanced technological inspections performed on modern pipelines. Small defect failures during hydrostatic tests can and do occur. Operators should incorporate new technologies, including research in general pipeline leak detection, to detect small leaks during hydrostatic tests whenever possible.

The records involved in hydrostatic testing should end up in the operator’s regulatory files (available at any time for inspection) and the integrity management files (used for integrity analysis and data integration). The records may end up in court in the worst-case scenarios. With new requirements to maintain these records for the life of the pipeline, due diligence acquisition efforts may include more documentation requests and the value of assets being adjusted in accordance with the accuracy and completeness of these records. Those signing off on the hydrostatic test must understand the end use and need for complete and accurate records.

Even new pipelines sometimes fail during hydrostatic tests, sometimes due to very small defects. More pressure testing is coming to the industry due to new regulations on gas gathering and pipelines without traceable, verifiable, and complete records. When hydrostatic tests are used to manage pipeline integrity, additional requirements apply. Regulators will scrutinize the records and qualifications of those personnel performing and approving tests more closely.

Pipeline hydrostatic test inspectors should be trained in the documentation of data required for the test and understand what the data being collected means. Engineering analysis should be performed to understand and have confidence that the pipeline does not contain very small leaking defects that could be easily missed if test data points are not examined closely. Pipeline operators should utilize the industry's best practices to establish and maintain pipeline integrity.

There are now new requirements for reporting pipeline failures in 49 CFR 192.617 and requirements to perform root cause analysis of those pipe failures. A root cause investigation into a significant failure may result in re-examining the original hydro test records, the approval of the tests, and what engineering analysis was performed.

[4] The Benefits and Limitations of Hydrostatic Testing, John F. Kiefner and Willard A Maxey

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