THE BENEFITS AND LIMITATIONS OF HYDROSTATIC TESTING

by

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INTRODUCTION

The purpose of this paper is to clarify the issues regarding the use of hydrostatic testing to verify pipeline integrity. There are those who say it damages a pipeline especially if carried out to levels of 100 percent of more of the specified minimum yield strength (SMYS) of the pipe material. These people assert that if it is done at all, it should be limited to levels of around 90 percent of SMYS. There are those who insist that pipelines should be retested periodically to reassure their serviceability. The reality is that if and when it is appropriate to test a pipeline, the test should be carried out at the highest possible level that can feasiblely be done without creating numerous test failures. The challenge is to determine if and when it should be done, the appropriate test level, and the test-section logistics that will maximize the effectiveness of the test.

The technology to meet these challenges has been known for 30 years. Nothing has arisen in the meantime to refute this technology. The problem is that people both within and outside the pipe industry either are not aware of the technology or have forgotten it, or for political reasons are choosing to ignore it.

In this document we show the following:

- It makes sense to test a new pipeline to a minimum of 100 percent of SMYS at the highest elevation in the test section.
- Pipe that meets the specified minimum yield strength is not likely to be appreciably expanded even if the maximum test pressure is 110 percent of SMYS,
- If hydrostatic retesting is to be conducted to revalidate the serviceability of a pipeline that is suspected to contain defects that are becoming larger with time in service, the highest feasible test pressure level should be used.
- If the time-dependent defects can be located reliably by means of an in-line-inspection tool, using the tool is usually preferable to hydrostatic testing.

We also note the following as reminders:

- When a pipeline is tested to a level in excess of 100 percent SMYS, a pressure-volume plot should be made to limit yielding.
- A test may be terminated short of the initial pressure target, if necessary, to limit the number of test breaks as long as the MOP guaranteed by the test is acceptable to the pipeline's operator.

And, we suggest that:

- Test-section length should be limited to prevent elevation differences within a test section from exceeding 300 feet.
- The pressure level for verifying integrity can be higher than the level needed to validate the MOP of the pipeline, and the integrity test to a level above 1.25 times MOP, if used, needs to be no longer than 1/2 hour.

BACKGROUND

The concept and value of high-pressure hydrostatic testing of cross-country pipelines were first demonstrated by Texas Eastern Transmission Corporation. Texas Eastern sought the advice of Battelle in the early 1950s as they began to rehabilitate the War Emergency Pipelines and to convert them to natural gas service. Prior to testing, these pipelines exhibited numerous failures in service due to original manufacturing defects in the pipe. The Battelle staff recommended hydrostatic testing to eliminate as many of these types of defects as possible. After being tested to levels of 100 to 109 percent of SMYS during which time "hundreds" of test breaks occurred, not one in-service failure caused by a manufacturing defect was observed. The news of this successful use of hydrostatic testing spread quickly to other pipeline operators, and by the late 1960s the ASA B31.8 Committee (forerunner of ASME B31.8) had established an enormous database of thousands of miles of pipelines that had exhibited no in-service ruptures from original manufacturing or construction defects after having been hydrostatically tested to levels at or above 90 percent of SMYS[1]. These data were used to establish the standard practice and ASA B31.8 Code requirement that prior to service, each gas pipeline should be hydrostatically tested to 1.25 times its maximum allowable operating pressure. Later, a similar requirement for liquid pipelines was inserted into the ASME B31.4 Code. When federal regulations for pipelines came along, the precedent set by the industry of testing to 1.25 times the MOP was adopted as a legal requirement.

Both field experience and full-scale laboratory tests have revealed much about the benefits and limitations of hydrostatic testing. Among the things learned were the following:

- Longitudinally oriented defects in pipe materials have unique failure pressure levels that are predictable on the basis of the axial lengths and maximum depths of the defects and the geometry of the pipe and its material properties[2].
- The higher the test pressure, the smaller will be the defects, if any, that survive the test.
- With increasing pressure, defects in a typical line-pipe material begin to grow by ductile tearing prior to failure. If the defect is close enough to failure, the ductile tearing that occurs prior to failure will continue even if pressurization is stopped and the pressure is held constant. The damage created by this tearing when the defect is about ready to fail can be severe enough that if pressurization is stopped and the pressure is released, the defect may fail upon a second or subsequent pressurization at a pressure level below the level reached on the first pressurization. This phenomenon is referred to as a pressure reversal[3, 4].

- Testing a pipeline to its actual yield strength can cause some pipe to expand plastically, but the number of pipes affected and the amount of expansion will be small if a pressure-volume plot is made during testing and the test is terminated with an acceptably small offset volume or reduction in the pressure-volume slope[5].

TEST-PRESSURE-TO-OPERATING-PRESSURE RATIO

The hypothesis that "the higher the test-pressure-to-operating-pressure ratio, the more effective the test", is validated by Figure 1. Figure 1 presents a set of failure-pressure-versus-defect-size relationships for a specific diameter, wall thickness, and grade of pipe. A great deal of testing of line-pipe materials over the years has validated these curves[2]. Each curve represents a flaw with a uniform depth-to-wall-thickness ratio. Nine such curves are given (d/t ranging from 0.1 to 0.9).

Consider the maximum operating pressure for the pipeline (the pressure level corresponding to 72 percent of SMYS). That pressure level is represented in Figure 1 by the horizontal line labeled MOP. At the MOP, no defect longer than 10 inches and deeper than 50 percent of the wall thickness can exist. Any such defect would have failed in service. Similarly, no defect longer than 4 inches and deeper than 70 percent of the wall thickness can exist, nor can one that is longer than 16 inches and deeper than 40 percent of the wall thickness.

By raising the pressure level above the MOP in a hydrostatic test, the pipeline's operator can assure the absence of defects smaller than those that would fail at the MOP. For example, at a test pressure level equivalent to 90 percent of SMYS, the largest surviving defects are determined in Figure 1 by the horizontal line labeled 90 percent of SMYS. At that level, the longest surviving defect that is 50 percent through the wall can be only about 4.5 inches. Compare that length to the length of the longest possible 50-percent-through flaw at the MOP; it was 10 inches. Alternatively, consider the minimum survivable depth at 90 percent SMYS for a 10-inch-long defect (the size that fails at the MOP if it is 50 percent through the wall). The survivable depth is only about 32 percent through the wall. By a similar process of reasoning, one can show that even smaller flaws are assured by tests to 100 or 110 percent of SMYS (the horizontal lines drawn at those pressure levels on Figure 1).

The point is that the higher the test pressure (above MOP), the smaller will be the possible surviving flaws. This fact means a larger size margin between flaw sizes left after the test and the sizes of flaws that would cause a failure at the MOP. If surviving flaws can be extended by operating pressure cycles, the higher test pressure will assure that it takes a longer time for these smaller flaws to grow to a size that will fail at the MOP. Thus, Figure 1 provides proof of the validity of the hypothesis (i.e., the higher the test-pressure-to-operating-pressure ratio, the more effective the test).

TESTING TO LEVELS ABOVE 100 PERCENT OF SMYS

Given the previous argument for testing to the highest feasible level, one needs to consider practical upper limits. In the case of a new pipeline constructed of modern high-quality, high-toughness line pipe, the maximum test level can generally be in excess of 100 percent of SMYS. Reasons why this will not cause significant yielding of the pipe are as follows.

First, as shown in Figure 2, the average yield strength of an order of pipe is usually well above the minimum specified value. Very few pieces will have yield strengths low enough to cause yielding at 100 percent of SMYS.

Secondly, when a buried pipeline is pressurized, it is restrained by the soil from shortening in the axial direction. This causes an axial tensile stress equal to Poisson's ratio times the hoop stress (Poisson's ratio is 0.3 for steel). What this means to testing to over 100 percent of SMYS is shown in Figure 3.

The tensile test commonly used to assess the yield strength of line pipe is a transverse, flattened uniaxial specimen designed to test the circumferential (hoop) direction tensile properties. A test of such a specimen reveals a unique value of yield strength at a certain value of applied stress. In Figure 3, that value is represented as 1.0 on the circumferential tensile stress to uniaxial yield stress ratio (vertical) axis. If one were to test the same type of specimen using a longitudinal specimen, the unique yield strength measured in the test could be plotted on Figure 3 at 1.0 on the longitudinal tensile stress uniaxial yield strength (horizontal axis). Negative numbers on the horizontal axis represent axial compressive stress. The typical line-pipe material exhibits an elliptical yield-strength relationship for various combinations of biaxial stress(4). As shown in Figure 3, this results in yielding at a higher value of circumferential tensile stress to uniaxial yield strength ratios than 1.0. In tests of pressurized pipes(6), the ratio for a buried pipeline (longitudinal tensile stress to circumferential tensile stress ratio of 0.3) was found to be about 1.09. So, this effect also suppresses yielding in a hydrostatic test of a pipeline to a pressure level in excess of 100 percent of SMYS.

To resolve how much yielding actually takes place, Texas Eastern designed a gauging pig in the mid 1960s to measure diametric expansion(5). In 300 miles of 30-inch OD X52 pipe, tested to a maximum of 113 percent of SMYS, they found only 100 joints of pipe (out of 40,000) that had expanded as much as 1.0 percent. In 66 miles of 36-inch OD X60 pipe tested to a maximum of 113 percent of SMYS, they found 100 joints of pipe (out of 6,600) that had expanded as much as 1.0 percent, still not a lot of expanded pipe.

PRESSURE-VOLUME PLOTS

Shown in Figure 4 is a pressure-versus-pump-stroke plot of an actual hydrostatic test. The plot is created by recording the number of pump strokes of a positive displacement pump as each 10 psig increase of pressure is attained. Prior to beginning the plot, it is prudent to hold the test section at a constant pressure to assure that there are no leaks. After it is established that there is no leak, the plot should be started at a pressure level no higher than 90 percent of SMYS for the low elevation point in the test section in order to establish the "elastic" slope of the plot. By projecting the elastic slope lines across the plot as shown, one can then record pump strokes and compare the evolving plot to those slopes. If and when the actual plot begins to deviate from the elastic slope, either some pipe is beginning to yield or a leak has developed. The pressurization can be continued in any event until the "double-the-strokes" point is reached. This is the point at which it takes twice as many strokes to increase the pressure 10 psi as it did in the elastic range. Also, we suggest stopping at 110 percent of SMYS if that level of pressure is reached before the double-the-stroke point. Once the desired level has been reached, a hold period of 30 minutes should establish whether or not a leak has developed. Some yielding can be taking place while holding at the maximum pressure. Yielding will cease upon repeated repressurization to the maximum pressure, whereas a leak likely will not.

Testing an existing pipeline to a level at which yielding can occur may or may not be a good idea. It depends on the number and severity of defects in the pipe, the purpose of the test, and the level of maximum operating pressure that is desired. More will be said about this in the next section of this paper.

Finally, on the subject of testing to actual yield, the following statements apply.

- Yielding does not hurt or damage sound pipe. If it did, no one would be able to make cold-expanded pipe or to cold bend pipe.
- Yielding does not damage the coating. If it did, one could not field-bend coated pipe or lay coated pipe from a reel barge.
- Very little pipe actually undergoes yielding in a test to 110 percent of SMYS.
- Those joints that do yield do not affect pipeline integrity, and the amount of yielding is small.
- The only thing testing to a level in excess of 100 percent of SMYS may do is to void a manufacturer's warranty to replace test breaks if such a warranty exists.

TESTING EXISTING PIPELINES

Testing of an existing pipeline is a possible way to demonstrate or revalidate its serviceability. For a variety of reasons, retesting of an existing pipeline is not necessarily the best means to achieve confidence in its serviceability, however. First a pipeline operator who elects to retest a pipeline must take it out of service and purge it of product. The downtime represents a loss of revenue and a disruption to shippers. Second, the operator must obtain test water. To fill 30 miles of a 16-inch pipeline, an operator would need nearly 40,000 barrels of water. This is equivalent to a 100 x 100-foot pond, 22 feet in depth. For 30 miles of 36-inch pipe, the volume required would be five times as large. After the test, the water is considered a hazardous material because of being contaminated with product remaining in the pipeline. And, a test break, if one occurs, releases contaminated water into the environment. Aside from these issues, some problematic technical considerations exist.

The most important reason why a hydrostatic test may not be the best way to validate the integrity of an existing pipeline is that in-line inspection is often a better alternative. From the standpoint of corrosion-caused metal loss, this is most certainly the case. Even with the standard resolution tools that first emerged in the late 1960s and 1970s this was true. Consider Figure 5. This figure shows the relative comparison between using a standard resolution in-line tool and testing a pipeline to a level of 90 percent of SMYS. The assumption is made in this case that the operator excavates and examines all "severe" and "moderate" anomalies identified by the tool, leaving only the "lights" unexcavated. In terms of the 1970s technology, the terms light, moderate, and severe meant the following:

- Light indications: metal loss having a depth less than or equal to 30 percent of the wall thickness
- Moderate indication: metal loss having a depth more than 30 percent of the wall thickness but less than 50 percent of the wall thickness
- Severe indication: metal loss having a depth more than 50 percent of the wall thickness.

In Figure 5, the boundary between "light" and "moderate" is nearly at the same level of failure pressure as the 90 percent of SMYS test for long defects, and it is well above that level for short defects. Because even the standard resolution tools have some defect length indicating capability, an in-line inspection on the basis represented in Figure 5 gives a better assurance of pipeline integrity than a hydrostatic test to 90 percent of SMYS. With the advent of high-resolution tools, the advantage shifts dramatically in favor of using in-line inspection instead of hydrostatic testing to validate the serviceability of a pipeline affected by corrosion-caused metal loss.

From the standpoint of other types of defects, the appropriate in-line-inspection technology is evolving rapidly and, in some cases, it has proven to be more effective than hydrostatic testing. One example is the use of the elastic-wave tool for detecting seam-weld defects in submerged-arc-welded pipe[7]. Another is the use of transverse-field magnetic-flux-leakage inspection to find seam anomalies along side or in the seams of electric-resistance-welded (ERW) pipe[8]. In these cases, the particular tools revealed defects that were too small to have been found by a hydrostatic test to any reasonable level up to and including 110 percent of SMYS. When a tool has established this kind of track record, a pipeline operator can justify using the tool instead of hydrostatic testing.

The concept of using in-line tools to detect flaws invariably raises the question about defects possibly not being detected. The reasonable answer is that the probability of non-detection is small (acceptably small in the authors' opinion) but not zero. In the same context, one must also recognize that hydrostatic testing is not foolproof either. One issue with hydrostatic testing is the possibility of a pressure reversal. That possibility is discussed below. The other issue is that because hydrostatic testing can leave behind defects that could be detected by in-line inspection, the use of hydrostatic testing often demonstrates serviceability for only a short period of time if a defect-growth mechanism exists. This possibility is discussed in our companion paper[9].

PRESSURE REVERSALS

A pressure reversal is defined as the occurrence of a failure of a defect at a pressure level that is below the pressure level that the defect has previously survived due to defect growth produced by the previous higher pressurization and possible subsequent damage upon depressurization. Pressure reversals were observed long before their probable cause was identified[(3)]. The pipeline industry supported a considerable amount of research to determine the causes of pressure reversals. The most complete body of industry research on this subject is Reference 4. Figure 6, taken from Reference 4, reveals the nature of experiments used to create and demonstrate pressure reversals. It shows photographs of highly magnified cross sections of the tips of six longitudinally oriented flaws that had been machined into a single piece of 36-inch OD by 0.390 inch w.t. X60 pipe. Each flaw had the same length but each was of a different depth giving a graduation in severities. When the single specimen containing all six flaws was pressurized to failure, the deepest flaw (No. 1) failed. By calculations based on their lengths and depths, the surviving flaws were believed to have been pressurized to the following percents of their failure pressures.

Flaw Number	**Test Pressure Level at Failure of Flaw No. 1 as a Percent of the Calculated Failure Pressure of the Flaw, percent**
2	97
3	94
4	91
5	89
6	87

As one can see, the tips of Flaws 2, 3, and 4 exhibit some crack extension as a result of the pressurization to failure. The nearer the defect to failure, the more crack extension it exhibited. In fact, due to its extension during the test, Flaw No. 2 is now deeper than Flaw No. 1 was at the outset. Logic suggests that if we could have pressurized the specimen again, Flaw No. 2 would have failed at level below that which it experienced during the testing of Flaw No. 1 to failure. Indeed, in similar specimens designed in a manner to allow subsequent pressurizations, that is exactly what often occurred. This type of testing led to an understanding of pressure reversals in terms of ductile crack extension occurring at near-failure pressure levels where the amount of crack extension is so great that crack closure upon depressurization does further damage leading to the inability of the flaw to endure a second pressurization to the previous level. The pressure reversal is expressed as a percent.

Pressure reversal = (original pressure minus failure pressure) divided by (original pressure times 100).

Once the cause was known, the next key question was: What is the implication of the potential for pressure reversals on confidence in the safety margin demonstrated by a hydrostatic test? This question has been answered in particular circumstances and the answer comes from numerous examples of actual hydrostatic tests*. Figure 7 is an example of an analysis of pressure reversals in a specific test. This figure is a plot of sizes of pressure increases or decreases (reversals) on subsequent pressurizations versus the frequency of occurrence of that size of increase or decrease. Among other things, these data show that upon pressurization to the target test-pressure level, a one-percent pressure reversal (34 psi) can be expected about once in every 15 pressurizations, a two-percent pressure reversal (68 psi) can be expected about once in every 100 pressurizations, and a three-percent pressure reversal (102 psi) can be expected about once in every 1,000 pressurizations. For a target test pressure level of 1.25 times the maximum operating pressure (MOP), the expectation of a 20-percent pressure reversal (enough to cause failure at the MOP) is off the chart, that is, it is an extremely low probability event (but not an impossible event).

There have been a handful of pipeline service failures in which a pressure reversal is the suspected but unproven cause. There is also one case of a large pressure reversal (62 percent) that was unequivocally demonstrated because it occurred on the fifth cycle of a five-cycle hydrostatic test[(4)]. It should be noted that most of the experiences of numerous and large pressure reversals in actual hydrostatic tests have involved flaws associated with manufacturing defects in or near ERW seams, particularly in materials with low-frequency welded (generally pre-1970) ERW pipe. But in most cases where numerous reversals occurred, the sizes of the actual pressure reversals observed are small (less than five percent). One thing seems clear - if a hydrostatic test can be successfully accomplished without the failure of any defect, the likelihood of a pressure reversal will be extremely small. It is the tests in which numerous failures occur that have the highest probabilities of reversals. And, when the number of reversals becomes large, the probability of a reversal of a given size can be estimated as was done on the basis of Figure 7.

PRACTICAL CONSIDERATIONS

For new pipeline materials made to adequate specifications with adequate inspection and pipe-mill testing, one does not expect test failures even at pressure levels corresponding to 100 percent or more of SMYS. Therefore, there is no reason not to test a pipeline constructed of such materials to levels in excess of 100 percent of SMYS. As has been shown, the higher the ratio of test pressure to operating pressure, the more confidence one can have in the serviceability of a pipeline. In the case of existing pipelines, especially the older ones, such test levels may be impossible to achieve, and if numerous test

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*In actual hydrostatic tests, direct evidence that pressure reversals are the result of the type of flaw growth shown in Figure 6 has seldom been obtained. However, a few such cases have been documented and it is assumed that defect growth is responsible for all such cases.

failures occur, the margin of confidence may become eroded by the potential for pressure reversals. Weighing against low test-pressure-to-operating-pressure ratios, on the other hand, is the fact that such tests, by definition, generate lower levels of confidence and buy less time between retests if the issue of concern is time-dependent defect growth. Some possible responses to this dilemma are discussed below.

First and foremost, as has already been mentioned, the use of an appropriate in-line-inspection tool is always to be preferred to hydrostatic testing if there is sufficient confidence in the ability of the tool to find the defects of significance. Most of the pipe in a pipeline is usually sound. Therefore, it makes sense to use a technique that will find the critical defects and allow their repair as opposed to testing the whole pipeline when it is not necessary. The industry now has access to highly reliable tools for dealing with corrosion-caused metal loss, and tools are evolving rapidly to detect and characterize cracks. As has been noted, some uses of these tools have already proven their value and, in those cases, their use in lieu of hydrostatic testing makes good sense.

There are still certain existing pipelines for which hydrostatic testing remains the best (in some cases the only) means to revalidate their serviceability. In those cases, the following advice may be useful. Determine the mill hydrostatic test level for the pipe. The mill-test certificates will show the level applied if such certificates can be found. Also, search the records for prior hydrostatic tests at or after the time of construction. Review the pressure levels and causes of mill-test or in-place test failures if they exist. If none of these records is available, look up the API 5L specification applicable to the time the pipe was manufactured. This will reveal the standard mill-test pressure for the pipe. Do not assume, if you do not know, that the pipe was tested in the mill to 90 percent of SMYS. This was not always the case especially for non-X grades and smaller diameter pipe materials. If you decide to test the pipe to a level in excess of its mill-test pressure for the first time ever, anticipate test failures. If you cannot tolerate test failures, consider testing to a level just below the mill-test pressure. This may mean, of course, that the MOP you validate is less than 72 percent of SMYS (the minimum test pressure must be at least 1.25 times the MOP for 4 hours plus 1.10 times MOP for 4 hours for a buried pipeline; (see Federal Regulation Part 195). Alternatively, if you can tolerate at least one test failure, pressurize to a level as high as you wish or until the first failure, whichever comes first. If you then conduct your 1.25 times MOP test at a level at least five percent below the level of the first failure, a second failure will be highly improbable.

It is always a good idea to conduct an integrity test as a "spike" test. This concept has been known for many years[4,], but more recently it has been advocated for dealing with stress-corrosion cracking[10]. The idea is to test to as high a pressure level as possible, but to hold it for only a short time (5 minutes is good enough). Then, if you can live with the resulting MOP, conduct your 8-hour test at a level of at least five percent below the spike-test level. The spike test establishes the effective test-pressure-to-operating-pressure ratio; the rest of the test is only for the purpose of checking for leaks and for meeting the requirements of Part 195.

SUMMARY

By way of summarizing, it is worth reporting that

- Test-pressure-to-operating-pressure ratio measures the effectiveness of the test
- In-line inspection is usually preferable to hydrostatic testing
- Testing to actual yield is acceptable for modern materials
- Pressure reversals, if they occur, tend to erode confidence in the effectiveness of a test but usually not to a significant degree
- Minimizing test-pressure cycles minimizes the chance for pressure reversals.

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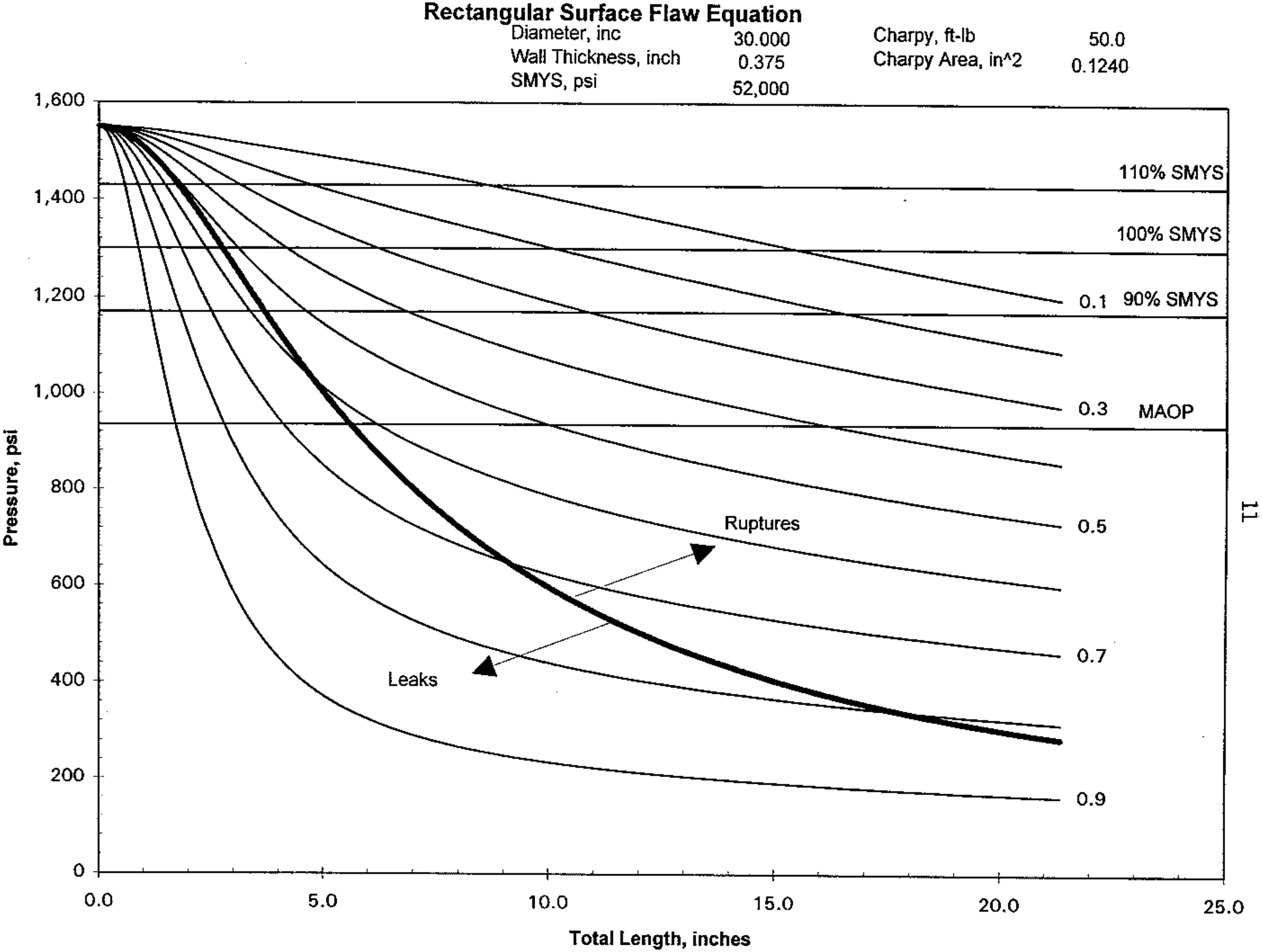


Figure 1. Impact of Test Pressure Levels on Margin of Safety

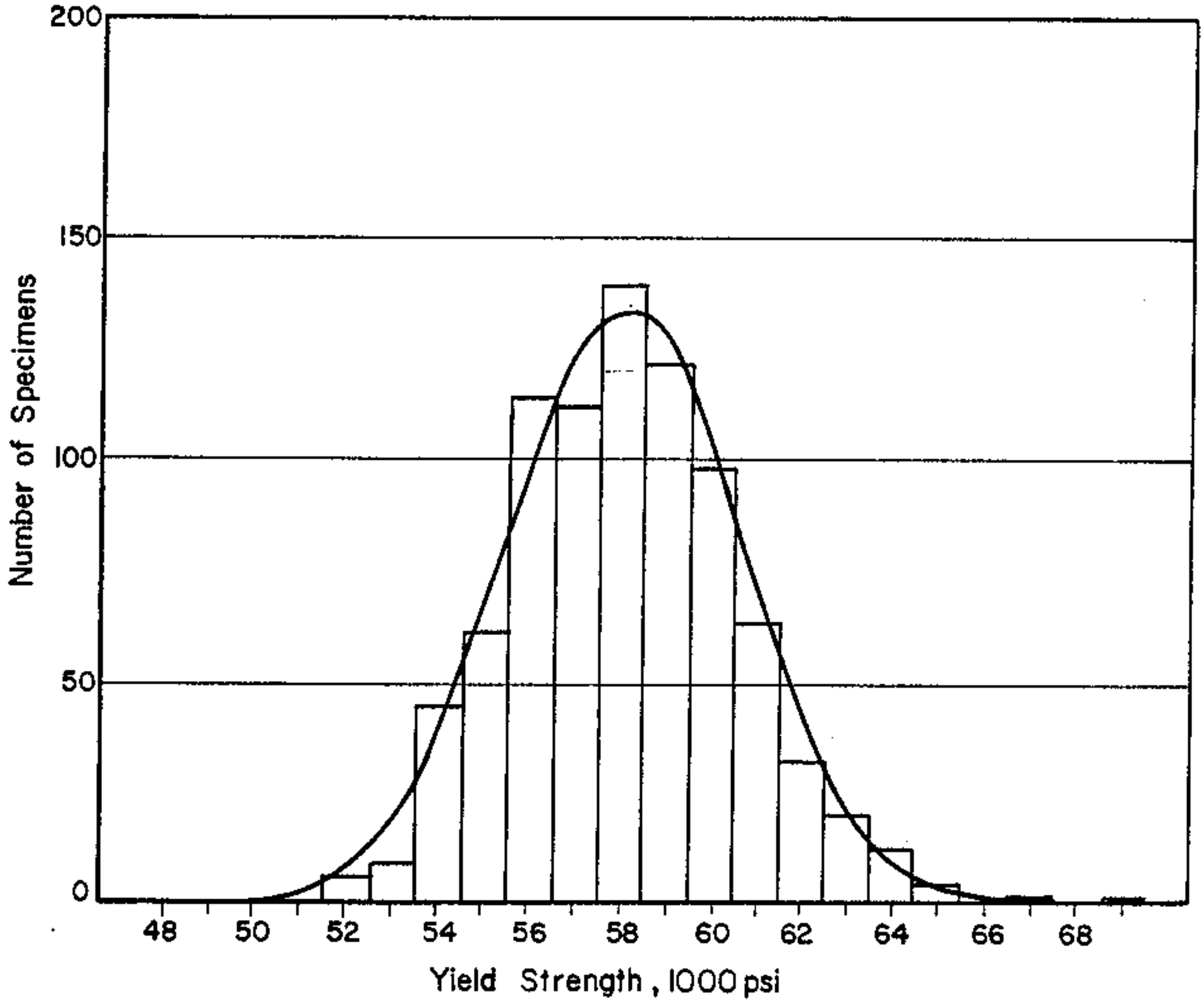


Figure 2. Normal Curve Fitted to Frequency Distribution of Yield Strength for 844 Pipe Specimens from 30-Inch by 0.375-Inch X52 Pipe

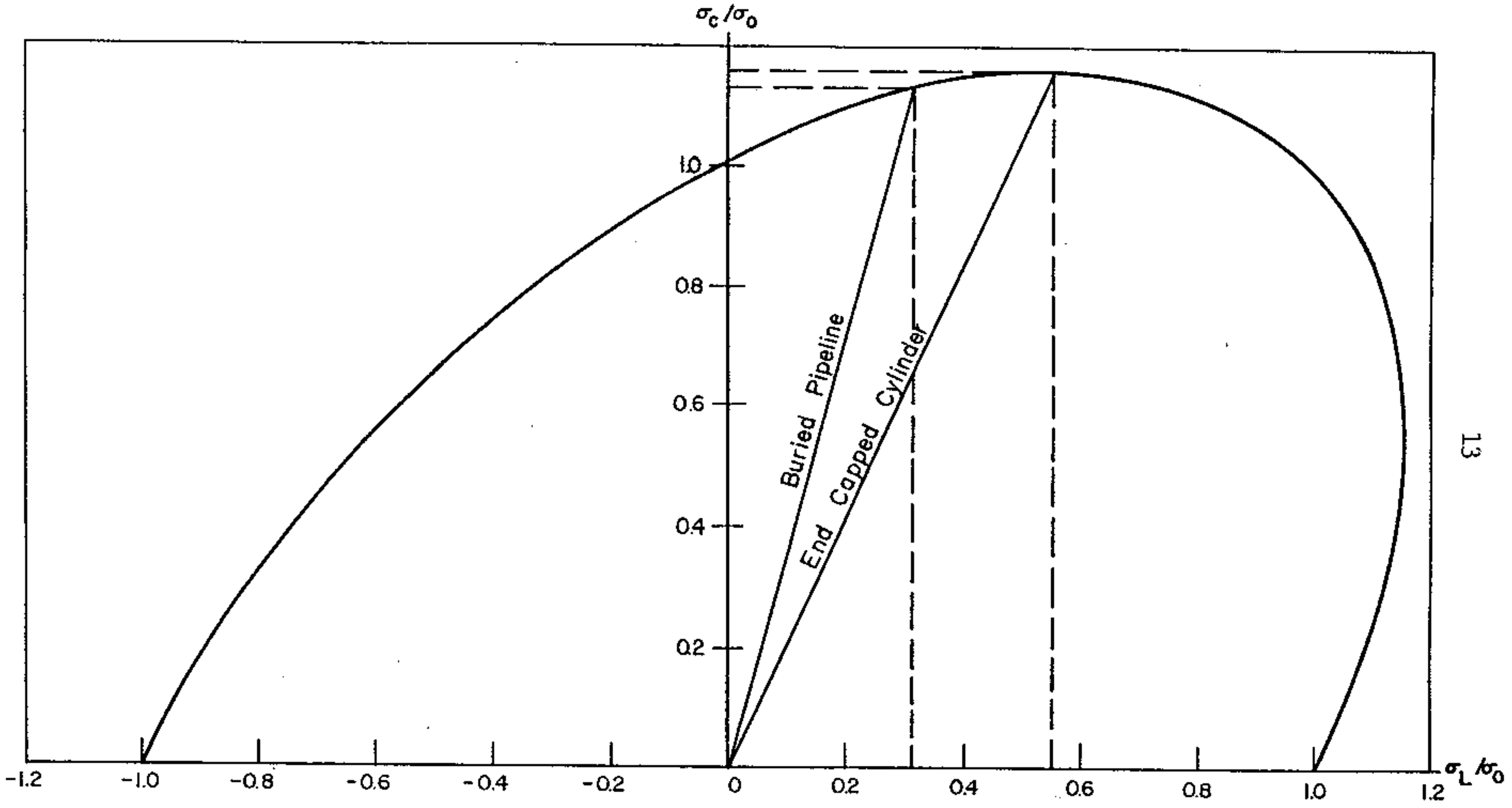


Figure 3. Explanation for Higher Yield Strength with Biaxial Tensile Stress

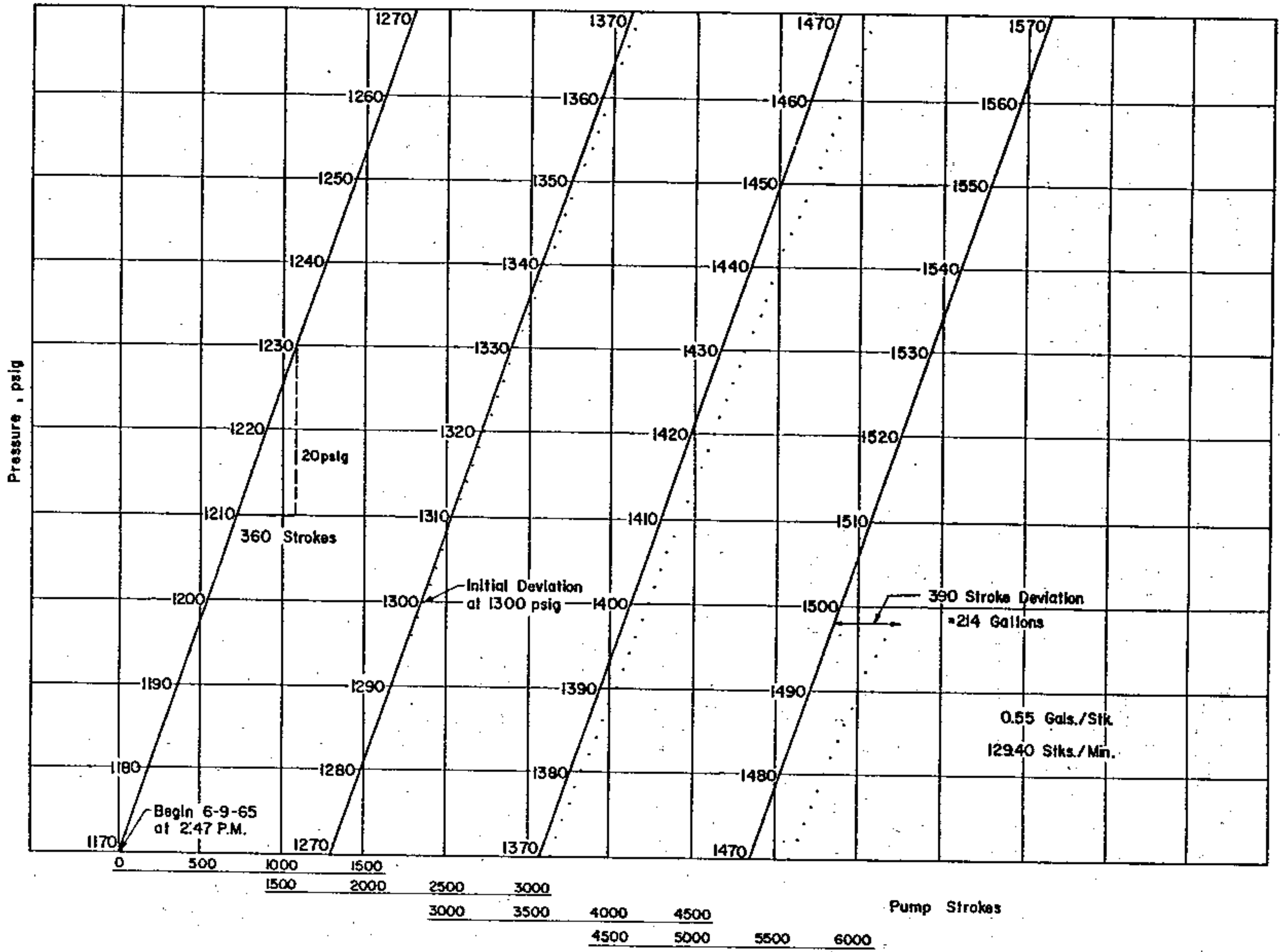


Figure 4. Typical Pressure-Volume Plot

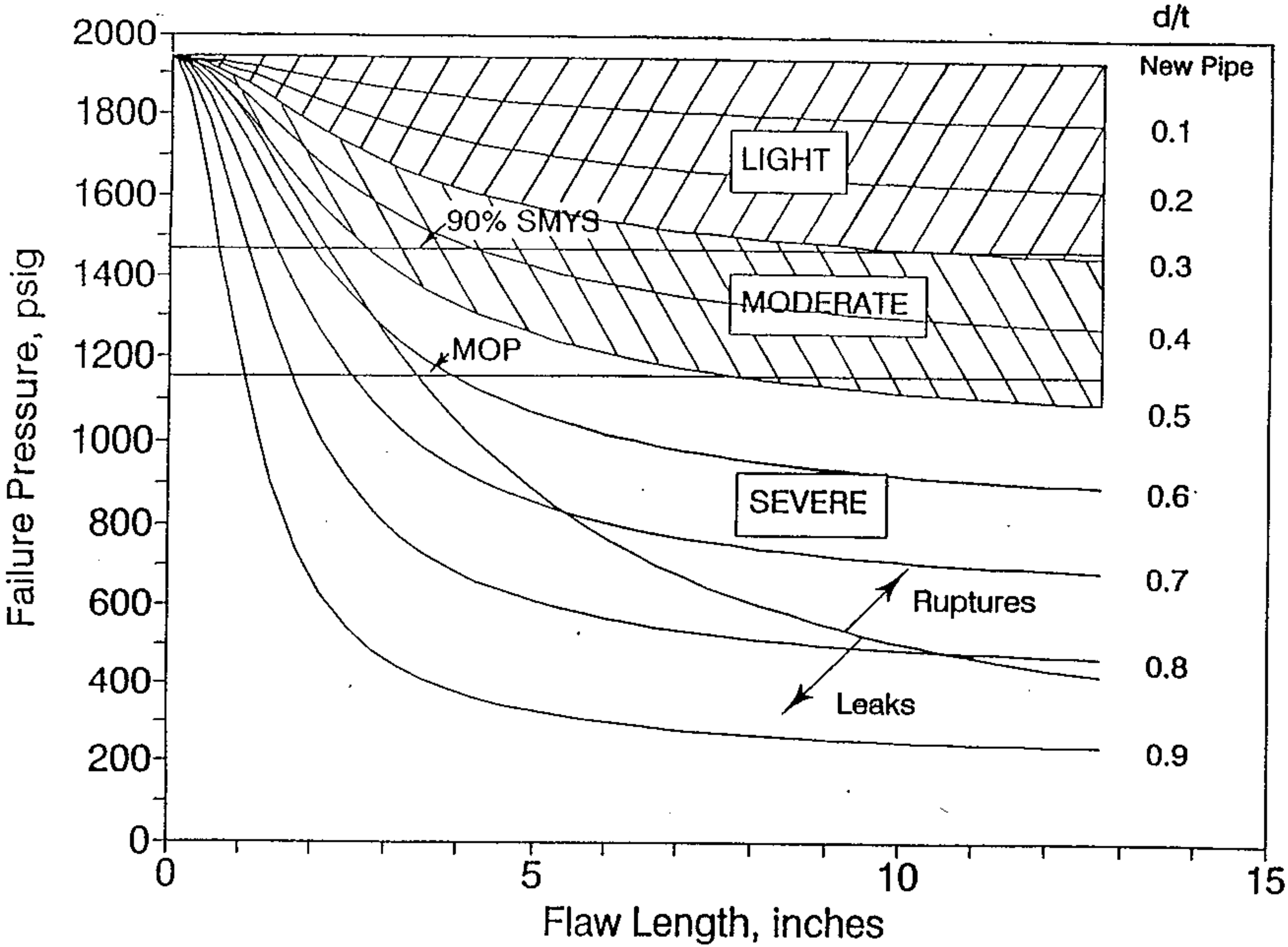
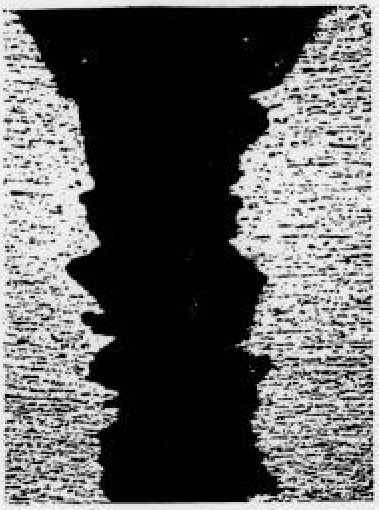


Figure 5. Sizes of Flaws Located by In-Line Inspection (Corrosion)
(16 Inch by 0.250 Inch X52, Blunt Defects)

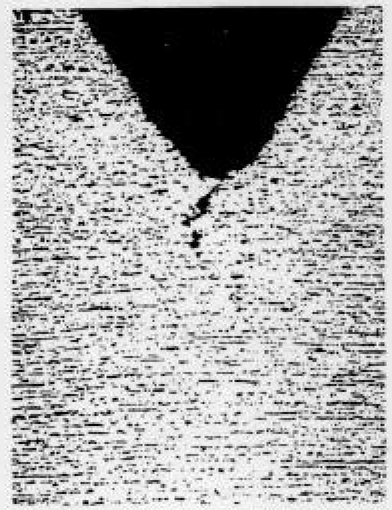


a. 1F602

Defect No. 1. Failure (Leak)
(L x d, 4.4 x 0.195 inch)

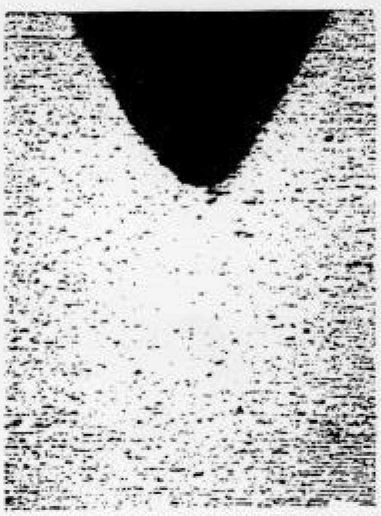
b. 1F603

Defect No. 2. 97 Percent of
Failure Stress Level
(4.4 x 0.171 inch)



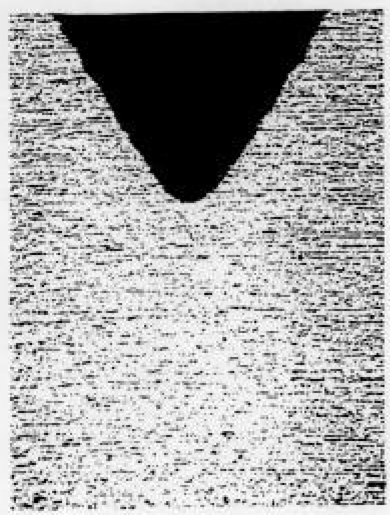
c. 1F604

Defect No 3. 94 Percent of
Failure Stress Level
(4.4 x 0.142 inch)



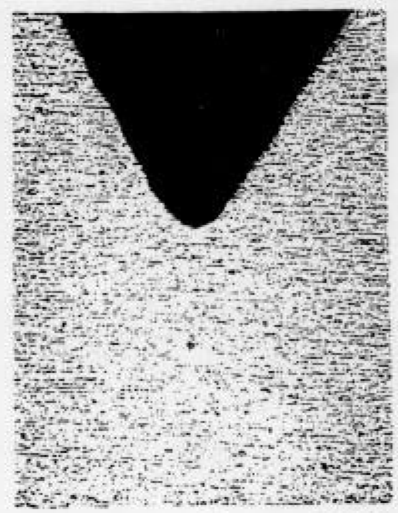
d. 1F605

Defect No. 4. 91 Percent of
Failure Stress Level
(4.4 x 0.125 inch)



e. 1F606

Defect No. 5. 89 Percent of
Failure Stress Level
(4.4 x 0.101 inch)



f. 1F607

Defect No. 6. 87 Percent of
Failure Stress Level
(4.4 x 0.078 inch)

Figure 6. Flaw Growth in 4.4-Inch-Long Part-Through Flaws in 36 x 0.390-Inch X60 Pipe

Note: Loading consisted of –
1st cycle – 0 → 1330 psig with 30 sec hold
2nd cycle – 0 → 1300 psig with 30 sec hold
3rd cycle – 0 → 1230 psig with 30 sec hold

Probability of a given pressure change on subsequent pressurization

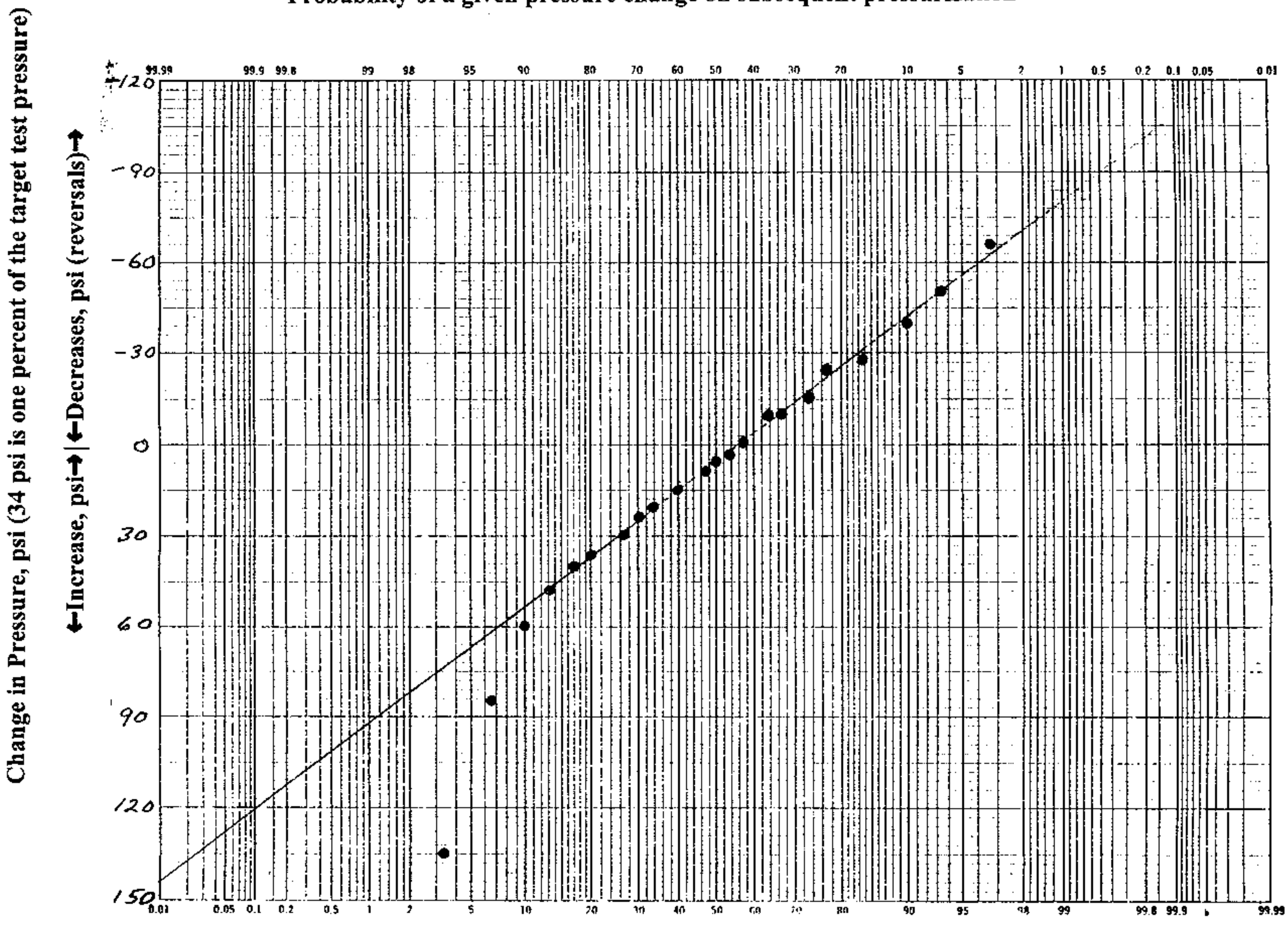


Figure 7. Evaluation of Probability of Having a Pressure Reversal