Vista Research Technical Note No. TN97-06

HYDROSTATIC PRESSURE TESTING OF BULK FUEL PIPING SYSTEMS

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27 June 1997

The work described in this paper was conducted by Vista Research, Inc., using internal funds.

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Abstract

An analysis was made of the performance of a *hydrostatic pressure test* (also called a *liquid pressure test*) when used for detection of petroleum fuel leaks in underground bulk transfer piping at terminals and fuel farms. The most commonly used standards, codes, and practices covering the conduct and interpretation of a test were reviewed, and the relevant procedures and criteria were incorporated into the analysis. Also presented and discussed are the results of a pressure test conducted under benign conditions on an operational 1,700-gal line at a bulk fuel farm. Using a hydrodynamic model, we calculated the magnitude of the pressure changes in this line and in two other lines of different sizes (3,133 gal and 12,533 gal); the three lines are representative of those at most bulk fuel farms and terminals. The purpose of the model calculations was to determine the magnitude of the pressure changes due to (1) increasing and decreasing product temperatures and (2) small leaks and large leaks (under both static and changing temperature conditions) and, furthermore, to do this under two conditions—with and without trapped vapor in the line.

The calculations and field test data indicate that the results of a pressure test are unreliable and highly ambiguous. They show that the magnitude of the pressure changes, as well as the time required for the pressure to change by a specified amount, are controlled by the volume of vapor in the line and the magnitude of the product temperature changes. They further show how increases in product temperature can mask leaks, and how decreases in temperature can be confused with leaks. They also show that large leaks may not effect large drops in pressure (as, for example, when trapped vapor is present and/or when product temperature is increasing), but that very large pressure drops can occur in a *nonleaking* line (as, for example, when product temperature decreases, particularly when there is no trapped vapor). Finally, the calculations show that the magnitude of the pressure changes *that are due to a leak* is dependent on line size.

The analysis indicates that the results of a pressure test cannot be interpreted properly without knowledge of the volume of trapped vapor in the line, the compressibility of the line, and the average change of product temperature during the test—quantities that are difficult to measure under field conditions. A review of the relevant standards, codes, and practices covering the conduct of these tests turned up no indication as to how to measure these quantities or use them to interpret the results of a test. Furthermore, this review indicated that the acceptance criteria used to interpret the results of a pressure test are ill-posed or ill-defined. Thus, one cannot determine from the results of a test whether or not a leak is present, and if one is thought to be present, what the leak rate is. In summary, there is no meaningful way to interpret the results of a pressure test on a buried line following any of the standard test procedures that were reviewed.

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1 Introduction

A *hydrostatic pressure test* (also called a *liquid pressure test*) is a commonly used method of leak detection for underground piping and pipelines. A test is conducted by isolating and pressurizing the line, and then measuring the change in pressure over a specified time. The line is declared tight if no pressure drop occurs. The line is declared leaking if a pressure drop does occur. Unlike other methods of leak detection for underground piping, the performance of this method has not been rigorously analyzed or subjected to an experimental evaluation following the standard procedures and practices of the EPA and ASTM [1,2].

This paper presents the results of analytical calculations that illustrate quantitatively the performance problems associated with using a *hydrostatic pressure test* to detect small leaks in underground lines. In these calculations, the effects on pressure of fuel temperature changes, piping leaks, and vapor trapped in the piping are addressed. Temperature changes in the product can produce pressure changes that are indistinguishable from those due to a leak; the thermally induced pressure changes can also mask and thus prevent detection of a leak. The presence of trapped vapor modifies the magnitude of both effects, complicating the interpretation of measured pressure changes (e.g., a small temperature change may cause a dramatic pressure change in piping that contains little entrapped vapor, while a large leak may cause only a very slight pressure change in a line containing a significant amount of vapor). Without a detailed understanding of the temperature conditions and the amount of trapped vapor in the piping under test, a meaningful interpretation of pressure test results is not possible.

The paper is organized as follows. Section 2 of the paper describes the standards, codes, and practices used to conduct and interpret a hydrostatic pressure test. Section 3 presents the results of an analysis of the pressure changes produce by a leak and by product temperature changes with and without any vapor in the line. Section 4 presents the results of a pressure test on a bulk fuel line. Section 5 summarizes the important results of the analysis.

2 Background

There are a variety of standards, codes, practices and procedures that describe a hydrostatic pressure test [3-8]. These tests were intended to verify the structural integrity of new lines and new sections of existing lines that can both be placed under a high pressure and inspected visually from the outside. These standards typically call for a pre-test waiting period (of unspecified duration) for temperature stabilization and a 4- or 8-h test duration. A brief description of the important aspects of the standards that affect the performance of the method is presented in Section 2.1. In Section 2.2, a brief description of a liquid pressure test method developed and used by a major petroleum company is presented, along with important aspects of the procedure that affect its ability to detect leaks reliably.

Only those aspects of the above-mentioned hydrostatic pressure test method that are required to analyze performance are described. They include the test pressure, the test medium, the test duration, the methods of temperature compensation, the precision and accuracy of the pressure and temperature gauges and sensors, and the criteria for passing or failing a test. For a more comprehensive description of a hydrostatic pressure test, the reader is referred to the standards themselves.

2.1 Common Standards, Practices, and Codes

The three most common standards, codes and practices for performing a hydrostatic pressure test—ASME B31.4, API 1110, and federal regulation 49 CFR Part 195—are very similar and cite each other as references [3-5]. All three documents, and very specifically ASME B31.4 and 49 CFR Part 195, were intended for use on *transportation pipelines*. ASME B31.4 is an American National Standard and constitutes a section of the *B31 Code for Pressure Piping*; the purpose of ASME B31.4 is to set forth "engineering requirements deemed necessary for safe design and construction of pressure piping." 49 CFR Part 195 is a federal regulation for transportation of hazardous substances by pipeline. API 1110 is a recommended practice for hydrostatic testing of new and existing liquid petroleum pipelines. The standard was prepared by API's Pipeline Transportation Committee on Design and Construction. The foreword of API 1110 states that "Liquid petroleum pipelines are pressure tested to verify that their test segments have the requisite structural integrity to withstand normal and maximum operating pressure and to verify that they are capable of liquid containment."

These three documents are often cited as references for a liquid pressure test on transportation pipelines and other types of pipelines and piping systems, both for tests of structural integrity and for leak detection. ASME B31.4 and 49 CFR Part 195 describe the minimum acceptable technical and regulatory requirements, respectively, of a hydrostatic pressure test (e.g., test pressures, test durations, test liquids). API 1110 recommends the minimum procedures to be followed when conducting a test, suggests the equipment to be used, and points out factors to be considered during the hydrostatic testing of liquid petroleum lines. Unfortunately, none of these documents describes the *criteria* for passing a hydrostatic test. Furthermore, while the important sources of error are pointed out (i.e., trapped vapor in the line and product temperature changes), there is no guidance or recommended practice as to how to deal with them effectively. This lack of specificity is a significant problem when these standards are applied to buried piping and pipeline systems that cannot be visually inspected during a test. Thus, the interpretation of the results of the test is left up to the test conductor.

For many applications, this lack of specificity has not been a problem because the standards were intended mainly to verify the structural integrity of new lines or replacement sections of lines that could be visually inspected for leaks when placed under a high test-pressure. With the advent of environmental regulations requiring periodic testing for leaks in underground pressurized lines, these standards have been cited as accepted practice for leak detection even though the method is ill-defined and the criterion is not specified. A liquid pressure test that is conducted according to these standards could not be used to test the small, 2-in.-diameter, 10- to 30-gal lines typically found at retail service stations, because it would not be in compliance with the EPA's UST environmental regulations [9]. However, liquid pressure tests are now accepted for testing the much larger lines, such as bulk fuel lines, marine transfer lines, and hydrant fuel distribution lines, as well as transportation lines. This practice is changing as methods specifically designed for detecting *small leaks* of environmental interest have been introduced into the marketplace. One example is Vista's LT-100 and HT-100 volumetric leak detection systems for bulk lines and airport hydrant fuel distribution systems [10,11].

While the criteria and methods of dealing with the most important sources of error that may occur during a test are not specified, these standards all specify the test pressure, test duration and test medium. Unless the operating pressure is less than 20% of the specified minimum yield strength of the pipe, all three documents call for a 4-h pressure test on all lines or line segments that can be visually inspected, where the pressure must remain at 125%, or more, of the internal design pressure during the entire test. An additional 4-h test is required if portions of the line cannot be visually inspected. In this second 4-hour period, the test must be conducted at a pressure that remains above 110%, or more, of the internal design pressure throughout the test. All pressure measurements should be made with a gauge or sensor that is certified for accuracy and is capable of measuring in increments of 1.5 psi or better. If the operating pressure is less than 20% of the specified minimum yield strength of the pipe, only a 1-h test is required. Such a test period is used by the Coast Guard in hydrostatic testing of marine terminal transfer lines [6]. A liquid pressure test can be performed with water or liquid petroleum, provided that the petroleum product does not vaporize rapidly.

API 1110 states that the test should not be conducted until after the product temperature has stabilized; if thermal expansion and contraction of the product will occur during the test (an absolute certainty for petroleum lines), the practice states that provisions should be made for pressure relief due to thermal expansion of the product; and the effects of thermal contraction (and expansion) should be taken into account when interpreting the pressure test results. To account for thermal contraction of the product, API 1110 requires that the temperature of the pipe wall be measured to the nearest 0.2 deg F at a point where the pipe has normal cover. Despite the requirement for stabilization and temperature compensation, no guidance on how to determine the stabilization period or how to use the temperature data is presented.

Since neither API 1110 nor any of the other standards, codes or practices provides guidance about accuracy or reliability requirements, it is impossible to select a stabilization period or to determine whether a *single-point* measurement of the pipe wall temperature alone is adequate to estimate the thermal expansion and contraction of the fuel throughout the entire pipe. Work done by Vista Research, presented in a recent technical paper, indicates that a waiting period of 24 to 36 h may be required for stabilization of bulk piping and longer periods for larger piping systems (e.g., airport hydrant systems and transportation line segments) [12]. For the small lines found at retail service stations, the stabilization period may be as long as 12 h [13]. In practice, no pre-test waiting would be entirely effective, regardless of its duration.

Both ASME B31.4 and API 1110 also indicate that all vapor should be removed from the line before testing. General instructions for accomplishing this task are given. However, neither document describes how to measure the volume of trapped vapor that is present in the line during a test. As will be shown below, without knowing how much vapor is in the line, it is impossible to accurately interpret the result of a pressure test.

As specified, a liquid pressure test has two basic problems. First, no methods are given to compensate for the sources of noise that degrade the performance of a test. Second, no pass-fail criteria are given for the test, which means it is impossible to make a reliable decision about the results of a test. Without specifying the details of the test procedure and the criteria, it is impossible to determine the performance of a pressure test in terms of probability of detection and probability of false alarm. Thus, the accuracy and reliability of the test is unknown. Without knowing the performance of the method, it is impossible to use the method effectively.

2.2 Liquid Pressure Tests for Bulk Fuel Lines

A liquid pressure test is one method that has been used by the petroleum industry and the military to test underground bulk piping at petroleum marketing terminals and military fuel farms. A description of one of the *standard procedures* used by a major petroleum company follows. This petroleum terminal standard (PTS) procedure is generally similar to the API and ASME procedures. The main difference is the use of a very short test time. In this case a 15-min test duration is used.

The PTS requires that a liquid pressure test be performed at least once a year on all active lines and immediately before the operating pressure of a line is increased or a line idle for more than four months is brought back into service. While the standard goes into great detail about the procedures and equipment required to conduct such a test, like the standards in Section 2.1, it is ambiguous about how to interpret the results of a test and how to deal with the important sources of error that control the performance of the test.

The PTS states that the test must be conducted at 150% of the normal operating pressure of the line, or 150 psi, whichever is greater. The test duration is 15 min, and a leak in the line is "indicated by a continuous drop-off in pressure" over this period, "with the rate of drop-off indicative of the leak size." The test procedure allows for a slight initial drop-off in pressure that may occur and comes to a stop upon pressurization. The pressure measurements must be made with a mechanical gauge that has a minimum diameter of 3 in. or an electronic sensor that has equal or better resolution and accuracy. A 3-in.-diameter gauge has divisions of 2 psi. The test can be performed with the existing product in the line.

The PTS further states that air pockets in the line should be eliminated before conducting a pressure test. This can be accomplished by venting the high points of the line or by pumping product through the system. The procedure states that air pockets may be present if it takes more than a few minutes to pressurize the line. The PTS gives no guidance, however, on how to determine if all of the vapor has been removed, what volume of vapor is acceptable for the conduct of a test, or how to make quantitative measurements of the volume of trapped vapor that remains in the line.

The procedure does not address the impact of product temperature changes on the test results and does not measure the temperature of the pipe wall or the product. The procedure does address the safety issue of over-pressurization caused by the thermal expansion of product when an aboveground portion of the line is exposed to sunlight and when an underground portion is influenced by a warmer surrounding backfill and soil.

3 Performance Analysis

Two sets of calculations were performed to illustrate the accuracy and reliability problems associated with a liquid pressure test. The calculations were performed for two different line sizes as a function of vapor, temperature and leak conditions. The output of the calculations is a time history of pressure that would be observed during a test.

Vista developed an analytical model to quantitatively calculate the pressure changes in a pressurized liquid pipeline as a function of time that are associated with a leak and product temperature changes in the presence of trapped vapor. While small, the effects of temperature changes of the vapor are included in the calculations. The model requires specification of the hole size (for determining the magnitude of a leak at any pressure), the initial volume of trapped vapor at the test pressure, and a time history of liquid temperature changes. The model also requires the coefficient of thermal expansion and the bulk modulus of the liquid and piping system. All of the calculations in this paper were performed for jet fuel. The model accounts for the changes in leak rate associated with pressure changes and the changes in the volume of vapor with both pressure and temperature changes. To help interpret the output of the model calculations in the absence of any quantitative criteria, the time required for the pressure to increase or decrease by 5% of the test pressure were calculated and tabulated.

3.1 Test Conditions

The product temperature conditions selected for the pressure test calculations are relatively benign, but they illustrate the adverse impact of product temperature changes on a liquid pressure test. The temperature changes of the product were generated from a field-validated, numerical underground pipeline heat conduction model [13]. Jet fuel that was either 2.5 deg F warmer or cooler than the surrounding backfill and soil was circulated through the pipe for 19 h to generate realistic pipeline temperature conditions. All of the pressure tests, regardless of test duration, were initiated 1 h after the circulation stopped to avoid the extremely steep temperature gradients that occur immediately after transferring operations cease. The temperature conditions established by EPA for evaluating the performance of a pipeline leak detection system are considerably more severe than the one used in the modeling and range from -25 deg F to + 25 deg F [1].

Figure 1 presents the time history of the fuel temperature conditions (y-axis on the left of the plot) used in the calculations. Figure 1(a) shows the time history for increasing fuel temperature, and Figure 1(b) shows the time history for decreasing fuel temperature; except for sense, the rate of change of temperature is the same for both the increasing and decreasing temperature fields. The hourly rate of change of temperature, in deg F/h, is also shown (y-axis on the right of the plot). The average rate of change of temperature and the thermally induced product volume changes for lines, which are 8 in. (3,133 gal) and 16 in. (12,533 gal) in diameter, are summarized in Table 1 for a 15-min, 30-min, 1-h, 4-h, and 8-h test durations. The average rate of change of temperature and product volume changes in hourly intervals over an 8-h test are presented in Table 2.

Table 1. Conditions in Two Lines after a 19-h Transfer of Product That Was Initially 2.5 deg F Warmer than the Surrounding Backfill and Soil

Test Duration (min)	Temperature Change (deg F/h)	Volume Change 3,133-gal Line (gal/h)	Volume Change 12,533-gal Line (gal/h)
15	0.554	0.959	3.837
30	0.499	0.864	3.458
60	0.413	0.715	2.860
240	0.197	0.340	1.364
480	0.130	0.224	0.890

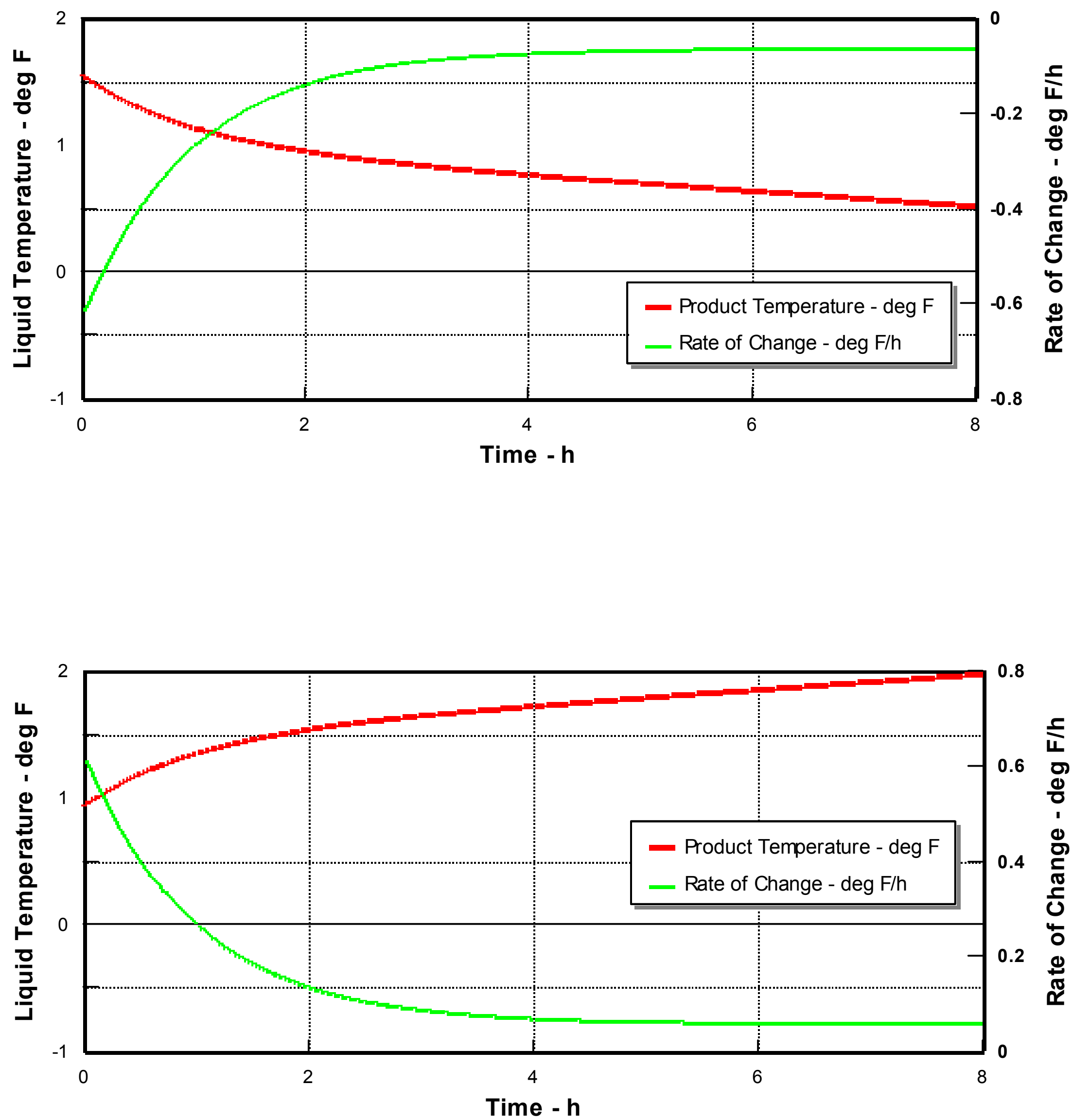

Figure 1. Increases in the temperature of product in a line after the product has been circulated for 19 h: (a) product that was initially 2.5 deg F warmer than the backfill and soil and (b) product that was initially 2.5 deg F cooler than the backfill and soil. The temperature is shown on the y-axis to the left of each plot, and the rate of change of temperature is shown on the y-axis to the right of each plot.

Table 2. Conditions in Two Lines after a 19-h Transfer of Product That Was 2.5 deg F Warmer than the Surrounding Backfill and Soil

Test Duration (h)	Temperature Change (deg F/h)	Volume Change 3,133-Gal Line (gal/h)	Volume Change 12,533-Gal Line (gal/h)
1	0.413	0.714	2.860
2	0.190	0.328	1.315
3	0.108	0.186	0.746
4	0.078	0.134	0.537
5	0.067	0.114	0.460
6	0.062	0.107	0.432
7	0.061	0.105	0.421
8	0.060	0.104	0.417

The magnitude of the leak and the pressure changes associated with it were calculated assuming free flow through a circular orifice. Figure 2 shows the flow rate through two holes of different diameter (0.00184 in. and 0.00411 in.), which were selected so as to produce leak rates of 0.2- and 1.0-gal/h, respectively, at 150 psig. In these calculations it was assumed that the operating pressure of the line was 100 psig and that the test pressure was 150 psig (i.e., 150% of the operating pressure). The magnitude of the leak for all calculations is reported at the test pressure. So is the volume of trapped vapor assumed for each calculation. As illustrated in Figures 1 and 2, the pressure changes associated with both the leak and product temperature changes are nonlinear.

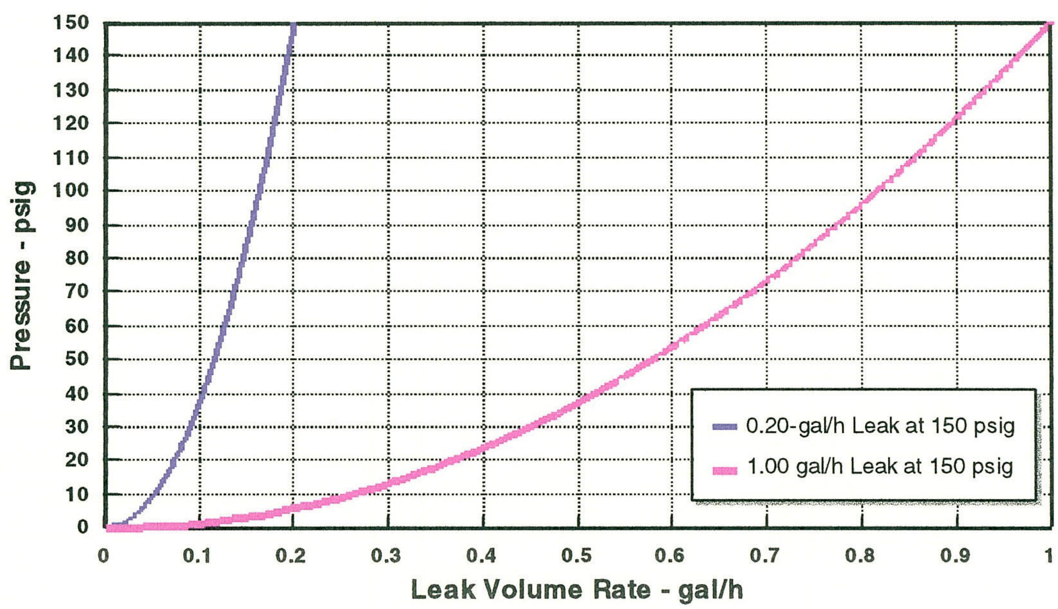

Figure 2. Flow rate as a function of pressure for two holes of different diameter selected so as to produce leaks of 0.2 and 1.0 gal/h at 150 psig.

Two sets of identical calculations were performed on two different-size lines; one of the lines was four times larger than the other. The smaller line—8 in. in diameter, 1,200 ft in length, and containing 3,133 gal of jet fuel—is representative of all but the largest lines found at most bulk fueling facilities. The larger line—16 in. in diameter, 1,200 ft in length, and containing 12,533 gal of jet fuel—is representative of the largest lines found at bulk fueling facilities. The results of these performance calculations are presented in Sections 3.2 and 3.3

Another set of calculations was performed on the underground line used to evaluate the performance Vista's LT-100 volumetric leak detection system at the NAS North Island fuel farm. This line—8 in. in diameter, 650 ft long, and containing 1,700 gal of jet fuel—is buried in sand 18 to 36 in. deep. It was selected because (1) it is typical of many bulk fuel farm lines and terminal lines and (2) its integrity is known. The evaluation covered (1) temperature conditions that ranged from -11 deg F to +22 deg F and (2) leaks randomly selected about 0.0, 0.05 ± 0.025, 0.10 ± 0.050, and 0.20 ± 0.050 gal/h. Several gallons to tens of gallons of vapor were trapped in the piping system as part of the evaluation. A hydrostatic pressure test of the line was conducted under known and relatively benign conditions. The compressibility of the line, the volume of trapped vapor, and the product temperature changes were measured as part of the test. The results of the pressure test, and the model calculations for this line, are discussed in Section 4.

Although we examined the effects of several different volumes of trapped vapor, we present only two cases here: a line with no trapped vapor and one that contains 0.5% vapor by volume. These two cases are sufficient to illustrate the impact of trapped vapor on a pressure test. The corresponding volumes of vapor for the 3,133- and 12,533-gal lines are 15.7 and 62.7 gal, respectively. For reference, a 1-ft section of line that is 8 in. in diameter contains 2.6 gal of fuel, and one that is 16 in. in diameter lines contains 10.4 gal.

The bulk modulus of the product used in these calculations (201,110 psi) was measured during the NAS North Island evaluation. The coefficient of thermal expansion for jet fuel measured at North Island and used in these calculations is 0.00056 /deg F.

The modeled pressure-test results are presented as a series of three pressure-versus-time plots for five different test durations. The results are displayed on three different plots for easier interpretation of the pressure changes. The results of the 15-min, 30-min, and 60-min tests are displayed on one plot. The results of the 4-h and 8-h tests are displayed on separate plots. As noted above, each test duration is typical of one currently being used in the conduct of hydrostatic tests. (The 15-min test duration is used by the petroleum marketing terminals, and the two longest tests are specified in ASME B31.4 and API 1110—the 4-h test duration for lines that can be visually inspected and the 8-h test duration for those that cannot be visually inspected [3,4]. The 30-min duration is currently used at one DOE site, and the 60-min test duration is used by the Coast Guard for pipelines at marine facilities [6]).

Each time-history graph contains six pressure curves. The first group of three curves (denoted by the thick red, thin green, and mid-thickness blue lines) shows the pressure changes that occur with a specified amount of trapped vapor in the line. The second set of three curves (denoted by the thick orange, thin purple, and mid-thickness teal lines) shows the pressure changes that occur when there is no trapped vapor. For each group, the plot shows the pressure changes associated with (1) only the leak (the blue and teal lines of middle thickness), (2) only the product temperature changes (the thin green and purple lines), and (3) both the leak and the temperature changes (the thick red and orange lines). The group of curves exhibiting the smallest pressure changes represent cases when the line contained trapped vapor. To allow easier identification of the predicted pressure changes, we have indicated, for each line, the 5% pressure-drop threshold.

3.2 Results for a 3,133-Gal Line

The calculations presented in this section are for lines containing slightly over 3,000 gal of fuel. As mentioned above, this capacity was selected because it is representative of the largest lines found at bulk fueling facilities.

The results of the model calculations for pressure tests up to 1 h in duration are shown in Figures 3 through 6. Figures 3 and 4 were generated for a leak of 0.2 gal/h for a decreasing and increasing product temperature condition, respectively. The average rate of temperature change ranged from $\pm$0.55 deg F/h for the 15-min test to $\pm$0.41 deg F/h for the 1-h test. Figures 5 and 6 were generated for a 1.0-gal/h leak. Figures 7 through 10 extend the results in Figures 3 through 6 for tests up to 4 h in duration. The average rate of change of temperature over the 4-h period was $\pm$0.20 deg F/h. The results of an 8-h test are presented in Appendix A. In practice, no pressure increases higher than 5% above the test pressure would be measured in the field because of the presence of the pressure relief valve set at 105% of the test pressure. Any pressure changes greater than 5% are shown only to illustrate the magnitude of these changes.

The pressure test results were quantitatively examined to determine how long it took for the pressure in the line to increase or decrease 5%. The results are summarized in Table 3. All pressure increases exceeding the +5% threshold are presented in square brackets "[ ]"; a second time is reported if the pressure also exceeds the -5% threshold. The remaining times are for pressure decreases. If neither $\pm$5% threshold was exceeded, the result was present as "> 8 h." Pressure changes as large as $\pm$5% could occur in less than 5 min or might take over 8 h, depending on the vapor, temperature, and leak conditions.

Table 3. Results of a Hydrostatic Pressure Test for a 3,133-gal Underground Pipe Tested at 150 psig. The table shows the time required for the pressure to increase or decrease by 5% of the test pressure. The volume of vapor is 0.5% by volume of the line capacity. In both the "No Vapor" and "Vapor" columns, TVR (thermally induced volume rate) indicates product temperature only; LVR (leak-induced volume rate) indicates a leak only—of either 0.2 or 1.0 gal/h; and "Both" indicates both product temperature and a leak.

			No Vapor			Vapor		
Product Temperature (incr/decr)	**Line Size (gal)**	**Leak Size (gal/h)**	**TVR (min)**	**LVR (min)**	**Both (min)**	**TVR (min)**	**LVR (min)**	**Both (min)**
Decrease	3,133	0.2	7.5	37	6	> 60	240	56
Decrease	3,133	1.0	7	7	3.5	> 60	53	27.5
Increase	3,133	0.2	[6.5]*	36	[8.5]*	[> 60]*	240	> 8 h
Increase	3,133	1.0	[6.5]*	8	40	[> 60]*	50	115

* [Time at which pressure has increased by 5%]

The results for product temperature decreases are described in Section 3.2.1, and the results for product temperature increases are described in Section 3.2.2.

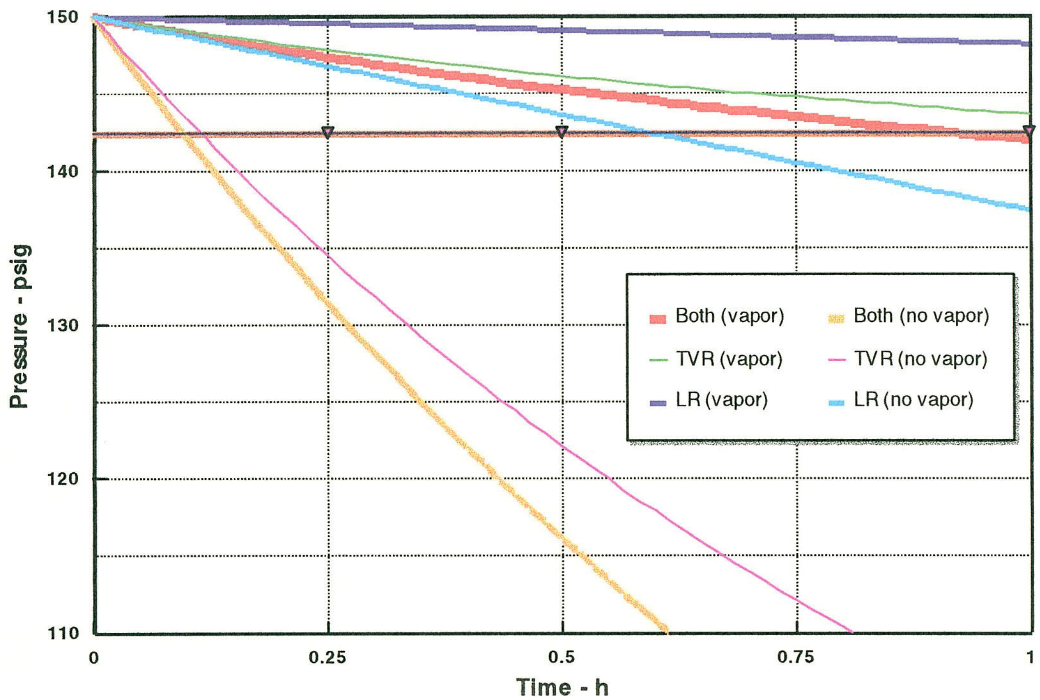

Figure 3. Results for pressure tests up to 1 h in duration on a 3,133-gal line with decreasing product temperature and a leak of 0.2 gal/h, with and without the presence of trapped vapor.

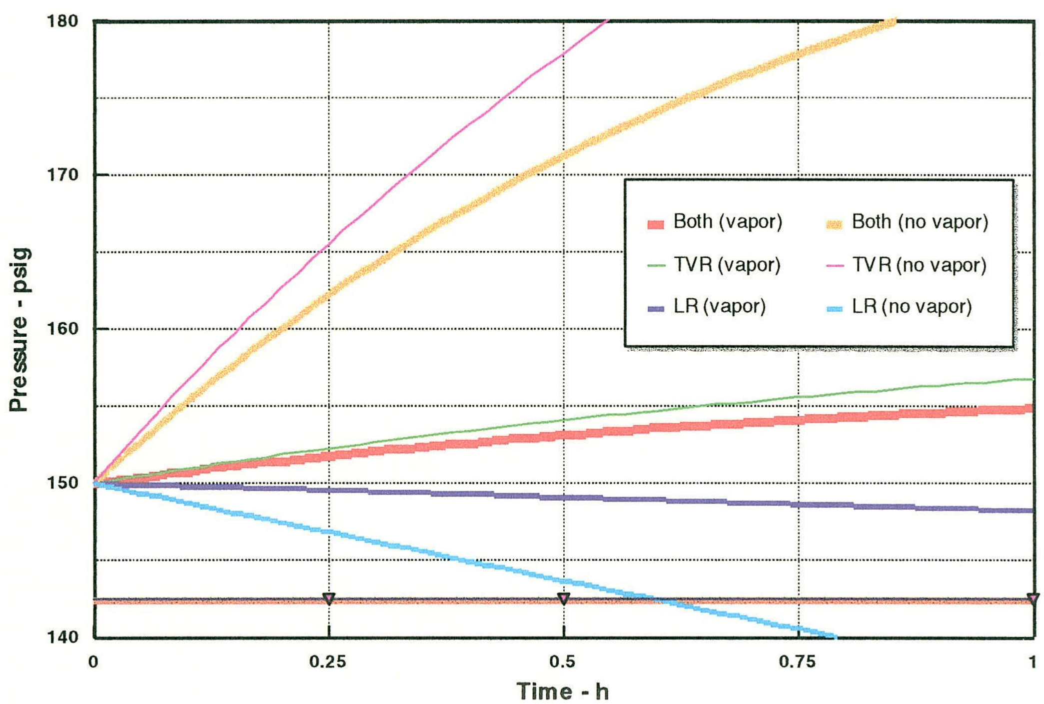

Figure 4. Results for pressure tests up to 1 h in duration on a 3,133-gal line with increasing product temperature and a leak of 0.2 gal/h, with and without the presence of trapped vapor.

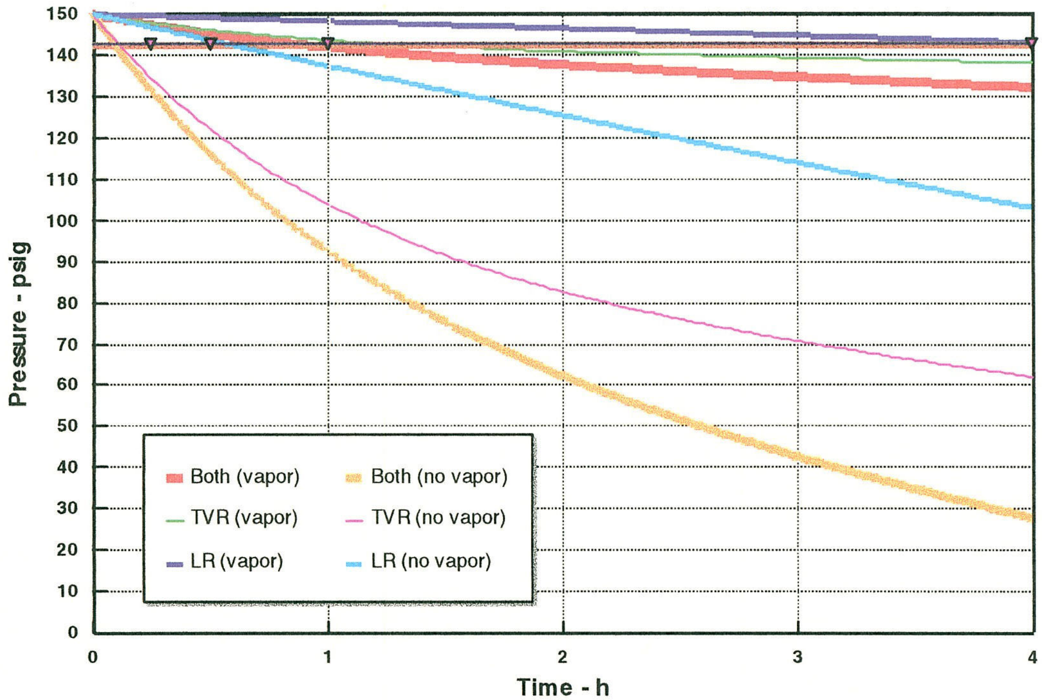

Figure 5. Results for pressure tests up to 4 h in duration on a 3,133-gal line with decreasing product temperature and a leak of 0.2 gal/h, with and without the presence of trapped vapor.

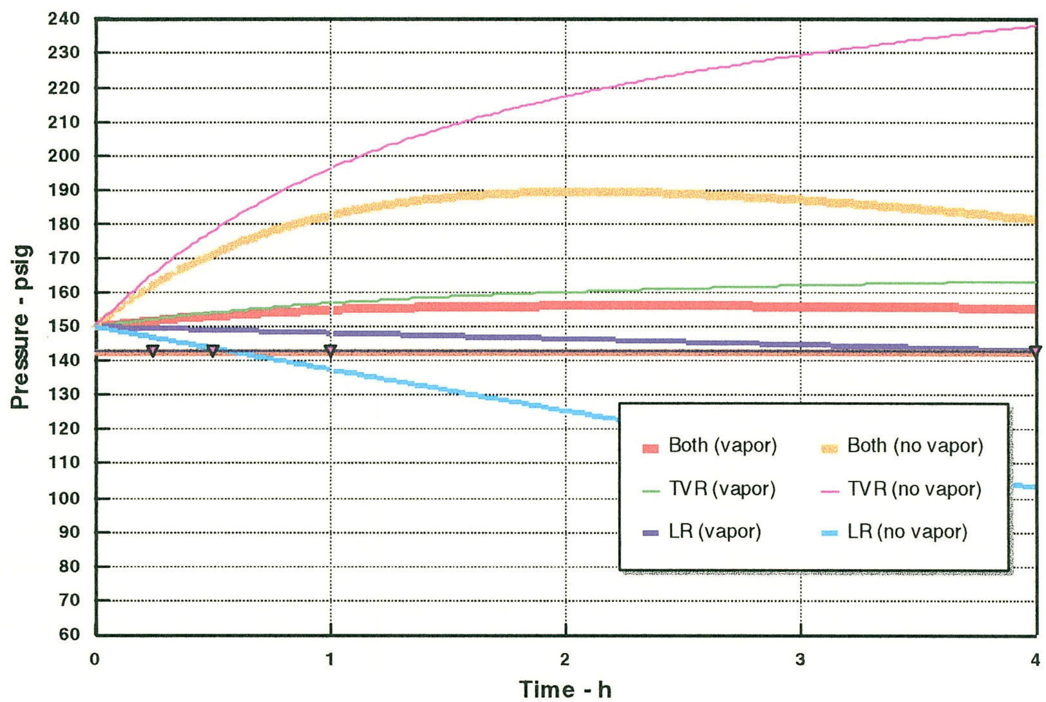

Figure 6. Results for pressure tests up to 4 h in duration on a 3,133-gal line with increasing product temperature and a leak of 0.2 gal/h, with and without the presence of trapped vapor.

3.2.1 Decreasing Product Temperature

Figure 3 shows that, when a line has no trapped vapor and the product exhibits no temperature changes, a test would have to be longer than 30 min to detect a 5% pressure drop that was due to a leak of 0.2 gal/h. As shown in Figure 5, a leak of 1.0 gal/h would produce an equivalent pressure drop in less than 10 min. Figure 7 shows that, when there *is* vapor in the line, it would take almost 4 h for a leak of 0.2 gal/h to produce a 5% pressure drop. As shown in Figure 9, it would take slightly less than 1 h for a leak of 1.0 gal/h to produce the same drop.

The thermally induced pressure changes are much larger than the pressure changes produced by a 0.2-gal/h leak and are slightly smaller than those produced by a 1.0-gal/h leak. In the absence of any vapor, it would take less than 10 min for the product temperature changes to produce thermally induced pressure changes of 5%. Such a large and quick pressure drop could be mistaken for a leak in all of the testing procedures. However, with vapor present, it would take over an hour to produce a 5% pressure change. This pressure change could also be mistaken for a leak in a 4-h or 8-h pressure test.

When the leak and the product temperature changes are combined, the time required for a leak of a given size to produce a 5% pressure change varies depending on whether trapped vapor is present in the line. When there is no trapped vapor, it takes 6 min for a 0.2-gal/h leak to produce a pressure drop of 5% and 3.5 min for a 1.0-gal/h leak to do the same. When vapor is present, the time required increases to 56 and 28 min, respectively.

3.2.2 Increasing Product Temperature

The results of a pressure test conducted under conditions of increasing product temperature are very instructive. Whereas decreasing thermally induced pressure changes may be confused with a leak, increasing thermally induced pressure changes can effectively mask the presence of a leak, especially a small one. Figures 4 and 8 show that under increasing temperature conditions a 0.2-gal/h leak would take more than 8 h to effect a 5% pressure drop. Thus a pressure test could not detect a leak of this size unless thermal changes in the product were compensated for. The pressure changes induced by a 1.0-gal/h leak are greater than the changes that are thermally induced. It takes about 2 h to produce a 5% pressure drop when vapor is present, and about 40 min if all the vapor has been successfully removed.

In the absence of a leak, the product temperature conditions used in these calculations would activate the pressure relief valve less than 10 min into a test when no vapor is present and in a little more than an hour when vapor is present. In fact, the results illustrated in Figure 8, when no vapor is present, suggest that it would be very difficult to sustain a test because the pressure relief valve would be repeatedly opening to relieve the pressure.

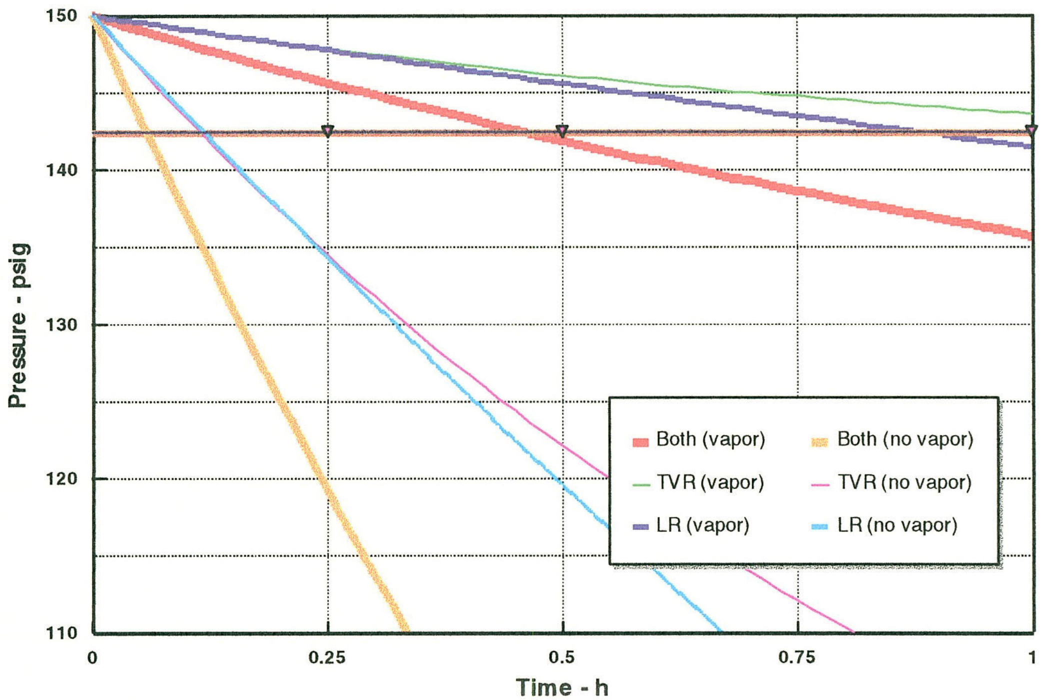

Figure 7. Results for pressure tests up to 1 h in duration on a 3,133-gal line with decreasing product temperature and a leak of 1.0 gal/h, with and without the presence of trapped vapor.

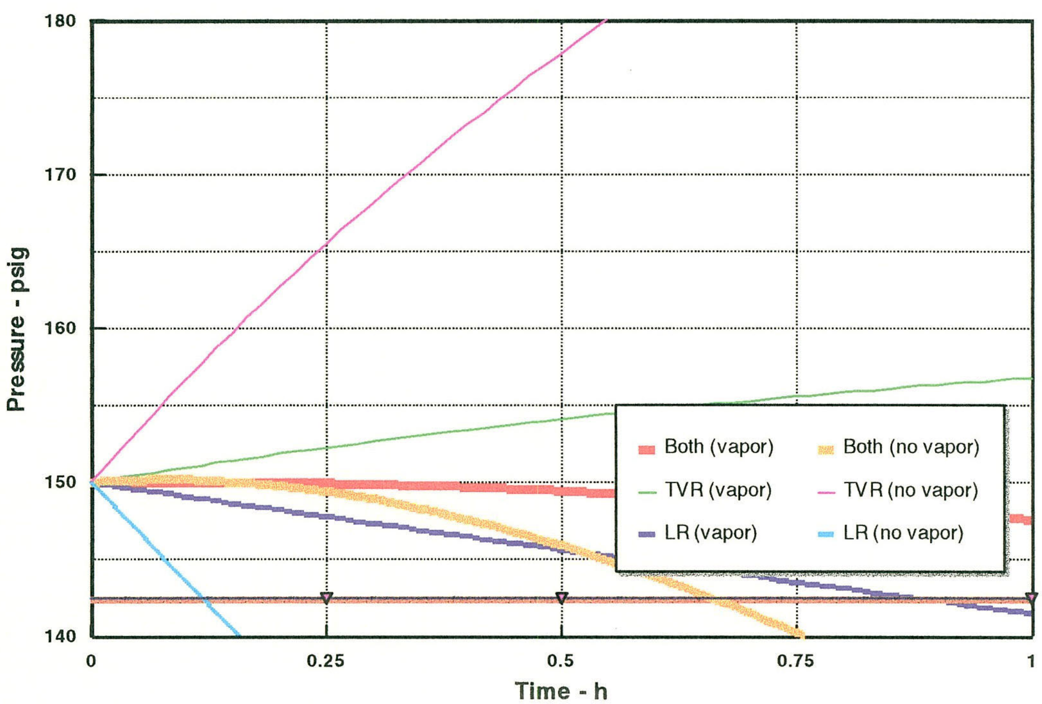

Figure 8. Results for pressure tests up to 1 h in duration on a 3,133-gal line with increasing product temperature and a leak of 1.0 gal/h, with and without the presence of trapped vapor.

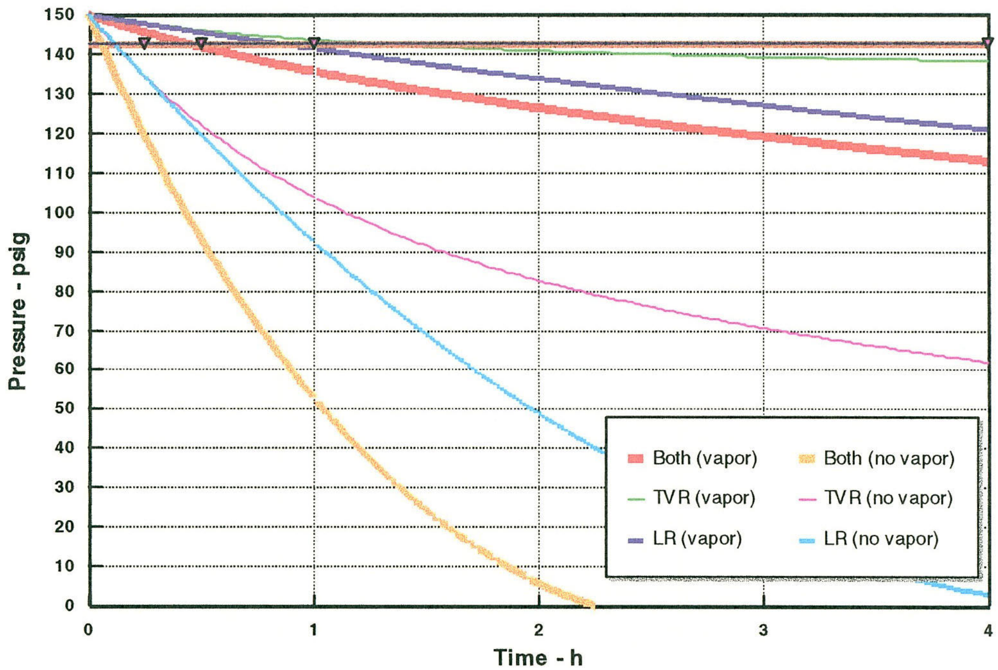

Figure 9. Results for pressure tests up to 4 h in duration on a 3,133-gal line with decreasing product temperature and a leak of 1.0 gal/h, with and without the presence of trapped vapor.

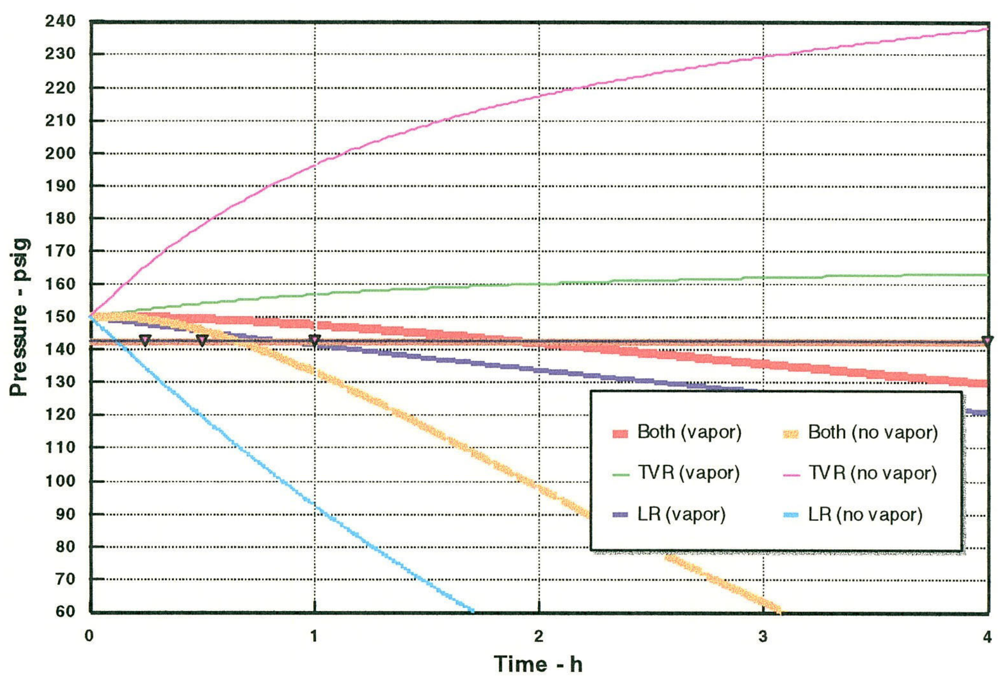

Figure 10. Results for pressure tests up to 4 h in duration on a 3,133-gal line with increasing product temperature and a leak of 1.0 gal/h, with and without the presence of trapped vapor.

3.3 Results for a 12,533-Gal Line

The calculations presented in this section are for lines containing slightly over 12,500 gal of fuel. This capacity is representative of some of the larger lines occasionally found at bulk fueling facilities.

The results of the model calculations for a 1.0-gal/h leak are shown in Figures 11 through 14 for pressure tests on the 12,533-gal line. Figures 11 and 12 present the results for tests up to 1 h in duration, and Figures 13 and 14 present the results for tests up to 4 h. Figures 11 and 13 were generated for a leak of 1.0 gal/h when the product temperature was decreasing during a test, and Figures 12 and 14 were generated for the same leak rate when product temperature was increasing. The calculations were performed for the same average temperature conditions as used for the 3,133-gal line. The results of an 8-h test are presented in Appendix B.

Table 4 presents the time required for the pressure to increase or decrease 5%. As reported in Table 3, all pressure increases exceeding the +5% threshold are presented in square brackets "[ ]"; a second time is reported if the pressure also exceeds the -5% threshold. The remaining times are for pressure decreases.

Table 4. Results of a Hydrostatic Pressure Test for a 12,533-gal Underground Pipe Tested at 150 psig.. The table shows the time required for the pressure to increase or decrease by 5% of the test pressure. The volume of vapor is 0.5% by volume of the line capacity. In both the "No Vapor" and "Vapor" columns, TVR (thermally induced volume rate) indicates product temperature only; LVR (leak-induced volume rate) indicates a leak only—of 1.0 gal/h; and "Both" indicates both product temperature and a leak.

			No Vapor			Vapor		
Product Temperature (incr/decr)	**Line Size (gal)**	**Leak Size (gal/h)**	**TVR (min)**	**LVR (min)**	**Both (min)**	**TVR (min)**	**LVR (min)**	**Both (min)**
Decrease	12,533	1.0	6.5	28	5	> 60	60+	52
Increase	12,533	1.0	[6.5]*	28	[10]*	[> 60]*	180	> 8 h

* [Time at which pressure has increased by 5%]

The results for product temperature decreases are described in Section 3.3.1, and the results for product temperature increases are described in Section 3.3.2

3.3.1 Decreasing Product Temperature

Table 5 presents a comparison of the times required to increase or decrease the pressure 5% for the 3,133-gal line and the 12,533-gal line. Figure 11 shows that without any vapor or any product temperature change, it takes approximately 30 min for a pressure drop of 5% to occur. When vapor is present, it takes over three hours to detect a 5% pressure drop. This compares to times of 7 min (without vapor) and 53 min (with vapor) for the smaller line, which means that the leak-induced pressure changes become smaller as the line increases in size. This is not true for the thermally induced pressure changes, which are the same for both the smaller and the larger lines. When vapor is present, it takes less than 1 h for the pressure to drop 5%; in the absence of vapor, such a pressure drop occurs in 5 min. These times are about twice those computed for the smaller line.

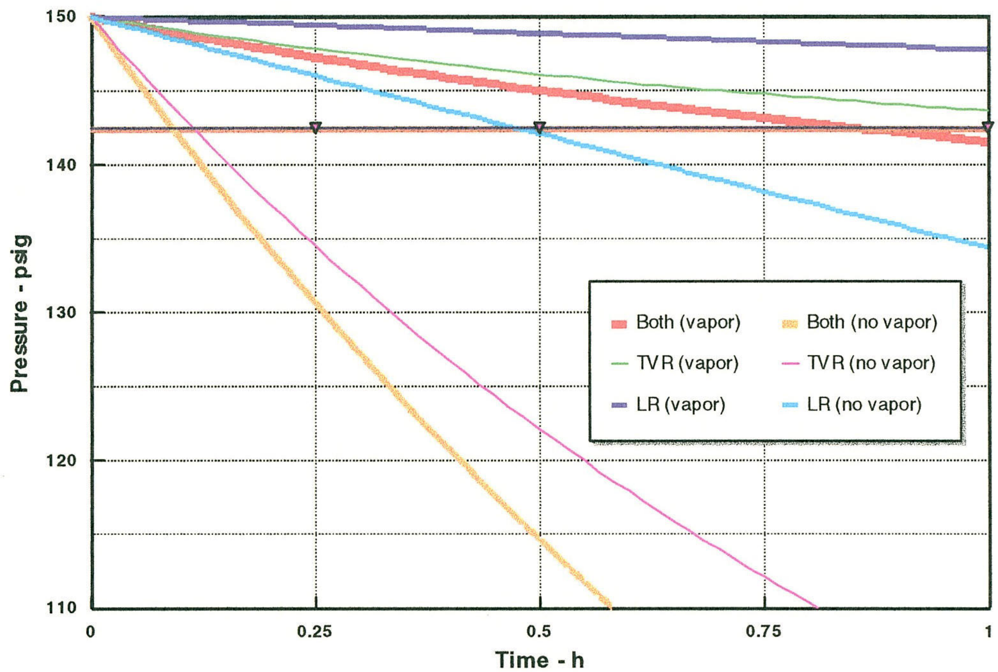

Figure 11. Results for pressure tests up to 1 h in duration on a 12,533-gal line with decreasing product temperature and a leak of 1.0 gal/h, with and without the presence of trapped vapor.

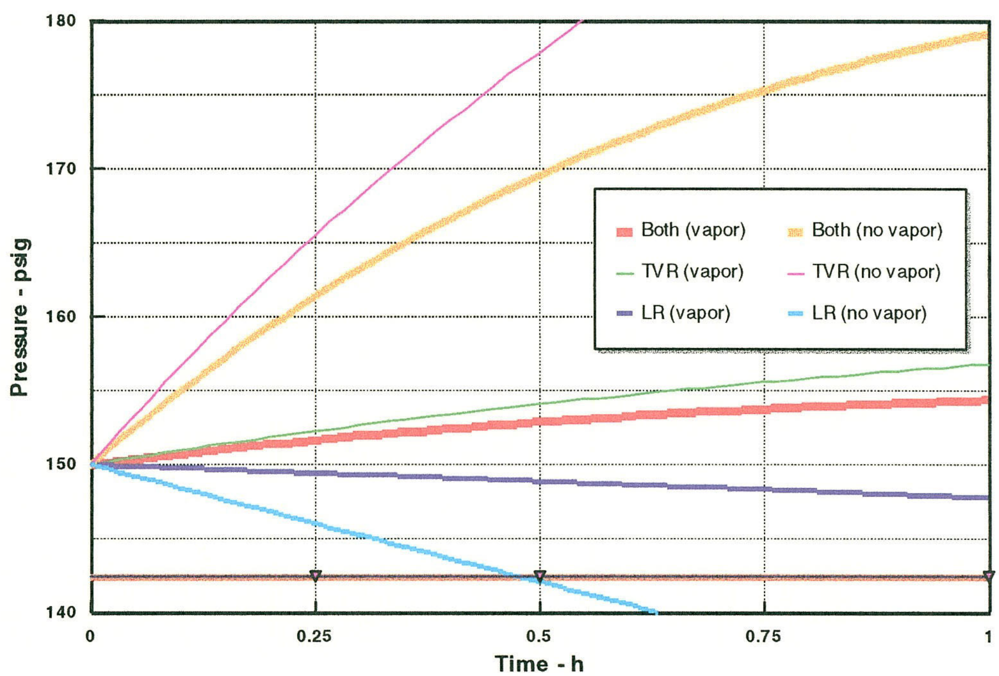

Figure 12. Results for pressure tests up to 1 h in duration for a line with increasing product temperature and a leak of 1.0 gal/h, with and without the presence of trapped vapor.

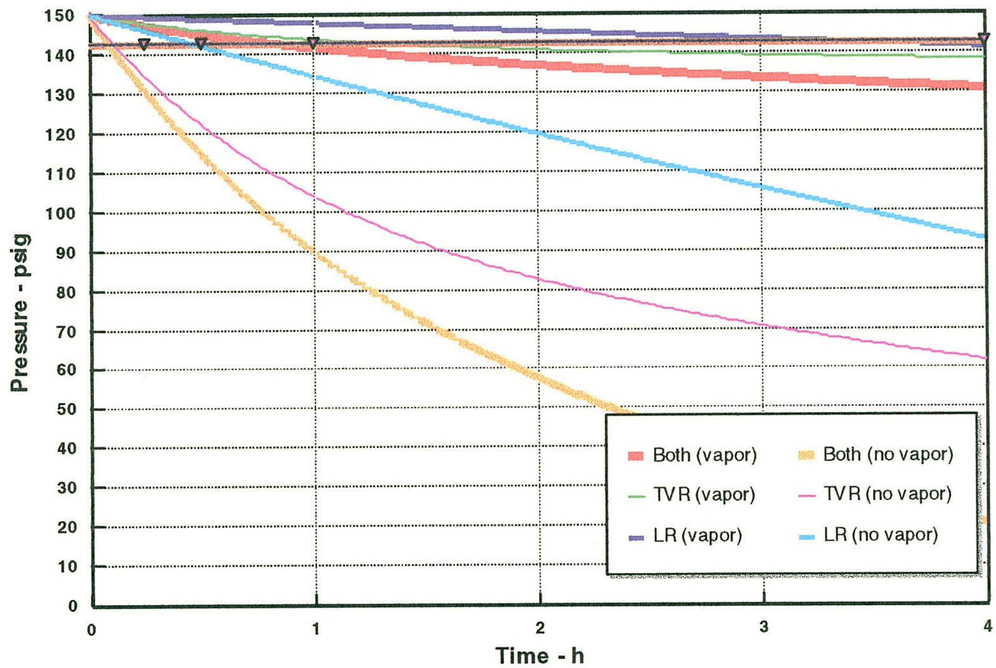

Figure 13. Results for pressure tests up to 4 h in duration on a 12,533-gal line with decreasing product temperature and a leak of 1.0 gal/h, with and without the presence of trapped vapor.

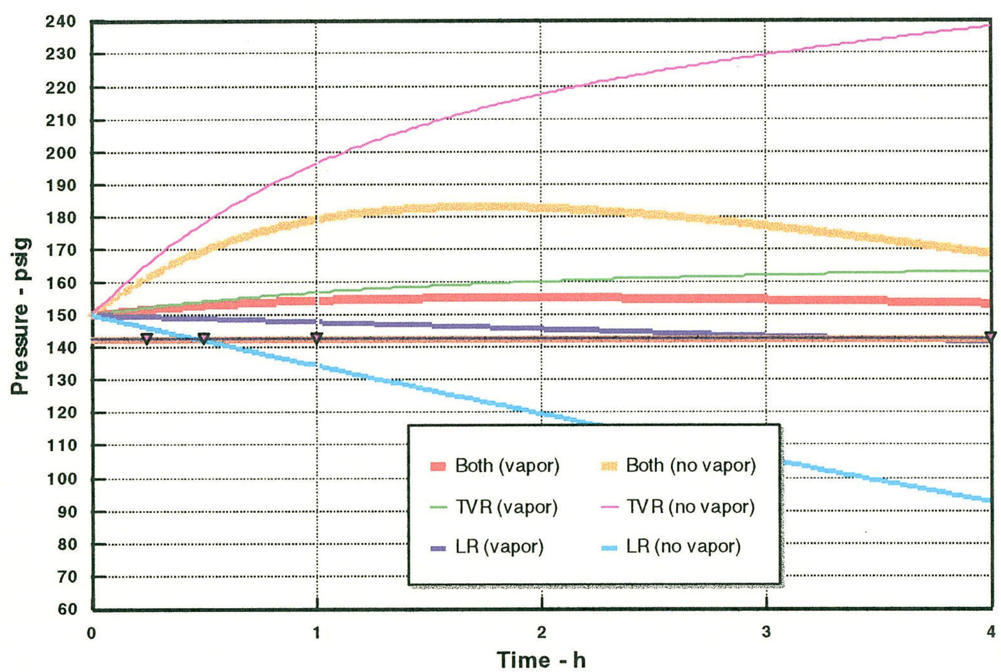

Figure 14. Results for pressure tests up to 4 h in duration on a 12,533-gal line with increasing product temperature and a leak of 1.0 gal/h, with and without the presence of trapped vapor.

Table 5. Results of a Hydrostatic Pressure Test for Decreasing Product Temperature and a 1.0-gal/h Leak on Underground Pipe Tested at 150 psig. This table compares the time required for the pressure to increase or decrease by 5% of the test pressure in two different-size lines (Tables 3 and 4), where one line is four times larger than the other.

			No Vapor			Vapor		
Product Temperature (incr/decr)	**Line Size (gal)**	**Leak Size (gal/h)**	**TVR (min)**	**LVR (min)**	**Both (min)**	**TVR (min)**	**LVR (min)**	**Both (min)**
Decrease	3,133	1.0	7	7	3.5	> 60	53	27.5
Decrease	12,533	1.0	6.5	28	5	> 60	60+	52

3.3.2 Increasing Product Temperature

Table 6 presents a comparison of the amounts of time required to increase or decrease the pressure by 5% for the 3,133-gal line and the 12,533-gal line. As illustrated in Figures 12 and 14, it takes over three times longer for leak-induced pressure changes to drop by 5% in the larger line than it does in the smaller line. In the larger line it takes over 3 h when trapped vapor is present, and slightly less than 30 min when it is not, as compared to 50 min and 8 min, respectively, in the smaller line.

Table 6. Results of a Hydrostatic Pressure Test for Increasing Product Temperature and a 1.0-gal/h Leak on Underground Pipe Tested at 150 psig. This table compares the time required for the pressure to increase or decrease by 5% of the test pressure in two different-size lines (Tables 3 and 4), where one line is four times larger than the other.

			No Vapor			Vapor		
Product Temperature (incr/decr)	**Line Size (gal)**	**Leak Size (gal/h)**	**TVR (min)**	**LVR (min)**	**Both (min)**	**TVR (min)**	**LVR (min)**	**Both (min)**
Increase	3,133	1.0	[6.5]*	8	40	[> 60]*	50	115
Increase	12,533	1.0	[6.5]*	28	[10]*	[> 60]*	180	> 8 h

* [Time at which pressure has increased by 5%]

In the presence of product temperature increases, a 1.0-gal/h leak does not effect a drop in pressure of 5% in an 8-h period, with or without vapor in the line. Thus, unless the temperature changes are compensated for, a leak of 1.0 gal/h cannot be detected. In the smaller line, a 1.0-gal/h leak produced a 5% pressure drop in slightly less than 2 h (vapor) and 40 min (no vapor).

In the absence of a leak, the increasing product temperature conditions used in these calculations would activate the pressure relief valve less than 10 min into a test when no vapor is present and in a little more than an hour when vapor is present. As noted for the smaller line, the results illustrated in Figure 14, when no vapor is present, suggest that it would be very difficult to sustain a test, because the pressure relief valve would be repeatedly opening to relieve the pressure.

4 Pressure Test on a 1,700-Gal Line

As stated in Section 3.1, a hydrostatic pressure test was conducted on the bulk transfer line used to evaluate the performance of Vista's LT-100 pipeline leak detection system. The results of the performance calculations made for this line are presented in Section 4.1. The results of the pressure test conducted on the line are presented in Section 4.2. The results of some of the modeling calculations are superimposed on the pressure-test data for comparison.

4.1 Model Calculations

Figures 15 through 17 show the results of the model calculations based on a leak rate of 0.1 gal/h for pressure tests up to 1, 4 and 8 h long, respectively. A small linear decrease in product temperature of 0.06 deg F/h that was observed during the actual testing was used to generate the pressure curves in these three figures. The volume of trapped vapor used in the calculations was 0.25% of line volume, which for this line is 4.25 gal. Table 7 gives the time required for the pressure in the line to drop by 5% of the test pressure (i.e., 3.7 psig).

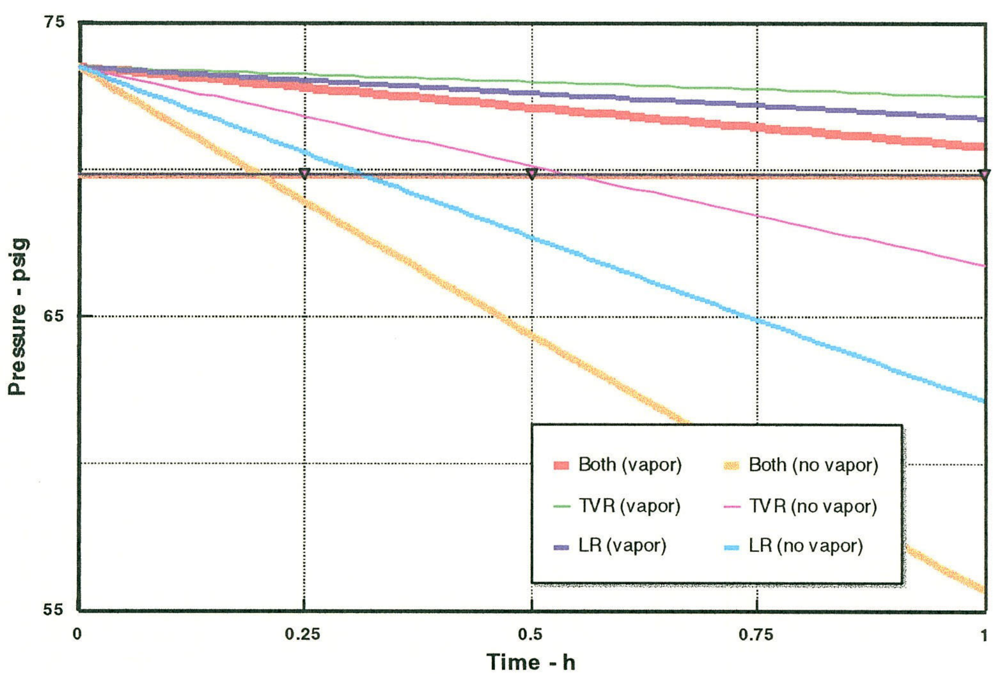

Figure 15. Results for pressure tests up to 1 h in duration on a 1,700-gal line with decreasing product temperature and a leak of 0.1 gal/h, with and without the presence of trapped vapor.

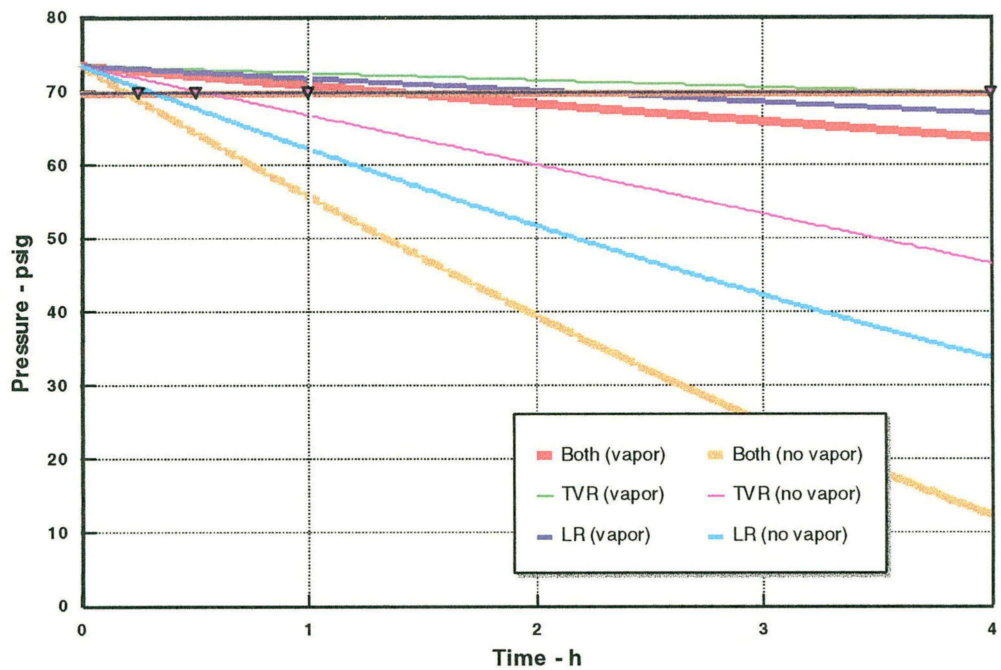

Figure 16. Results for pressure tests up to 4 h in duration on a 1,700-gal line with decreasing product temperature and a leak of 0.1 gal/h, with and without the presence of trapped vapor.

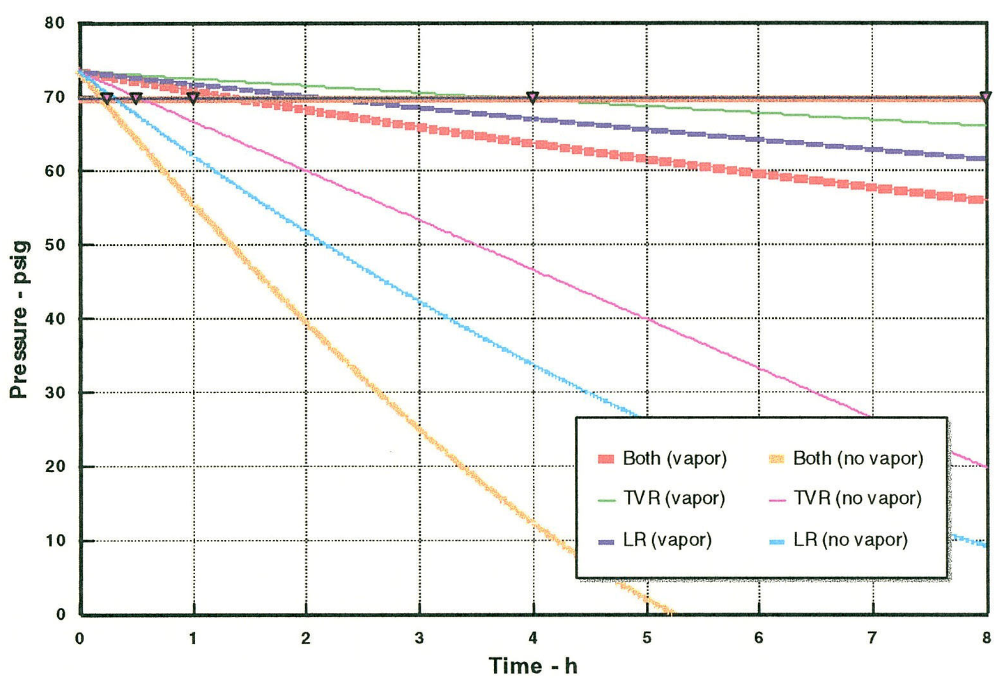

Figure 17. Results for pressure tests up to 8 h in duration on a 1,700-gal line with increasing product temperature and a leak of 0.1 gal/h, with and without the presence of trapped vapor.

Table 7. Results of a Hydrostatic Pressure Test for a 1,700-gal Underground Pipe Tested at 150 psig. The table shows the time required for the pressure to increase or decrease by 5% of the test pressure. The volume of vapor is 0.25% by volume of the line capacity. In both the "No Vapor" and "Vapor" columns, TVR (thermally induced volume rate) indicates product temperature only; LVR (leak-induced volume rate) indicates a leak only—of 0.1 gal/h; and "Both" indicates both product temperature and a leak.

			No Vapor			Vapor		
Product Temperature (incr/decr)	**Line Size (gal)**	**Leak Size (gal/h)**	**TVR (min)**	**LVR (min)**	**Both (min)**	**TVR (min)**	**LVR (min)**	**Both (min)**
Decrease	1,700	0.1	32	18	12	210	135	< 90

Figure 15 shows that, when a line has no trapped vapor and the product exhibits no temperature changes, a test would have to be slightly longer than 15 min to detect a 5% pressure drop that was due to a leak of 0.1 gal/h. As shown in Figure 16, if this line contained a 0.25% vapor by volume (4.26 gal), it would take 2 h longer for the pressure to drop 5%. If the line were tight and contained trapped vapor, it would take approximately 3.5 h; if the line did not contain trapped vapor it would take only a little more than 30 min. If the effects of product temperature were factored in, it would take slightly less than 90 min for the pressure to drop by 5% in a line with trapped vapor, but only 12 min if no vapor were present.

A number of observations can be made from the results shown in Figures 15 through 17. First, these results clearly show that the magnitude of the pressure drop is dependent on the volume of vapor in the line. When vapor is present, it takes 1 to 4 h to produce a 3.7-psi drop in pressure. Without any vapor in the line, the pressure drops in a matter of tens of minutes. Without a measurement of the volume of trapped vapor, it is nearly impossible to interpret the results of the pressure test.

Second, the thermally induced pressure changes are similar in magnitude to those produced by a small leak. When the product temperature changes are great, as they were during the evaluation of Vista's pipeline leak detection system, thermally induced pressure changes are considerably larger than leak-induced pressure changes.

Third, the thermally induced pressure changes would always be large enough to indicate the presence of a leak in a 4-h or 8-h test. The underlying ambient product thermal conditions during the test are typical of benign conditions.

Fourth, in the presence of vapor, the combined pressure changes for any test shorter than 1 h would not indicate the presence of a leak, if one were present. A 15-min test would not detect the presence of a small leak, even if all the vapor had been removed from the line. On the other hand, without any vapor present, the combined pressure changes would always indicate the presence of a leak.

Fifth, all of the pressure changes, whether due to thermal influences or to a leak, exhibit a continuous drop, as required by the criterion given in the petroleum terminal standard. However, because this criterion does not differentiate between thermally induced and leak-induced pressure changes, it is not considered robust.

4.2 Pressure Test Results

Vista Research conducted a liquid pressure test on a 1,700-gal underground line in San Diego, California. The test was conducted on a clear night in late September, between 2003 and 0403 (with additional pressure data collected through 0645). The amount of trapped vapor in the line was negligible—less than 0.01 gal as measured by Vista's unique method. Portions of the line that lay in open, concrete valve pits—approximately 20 to 24 ft, or 3.7%, of the 650-ft line—were exposed to the air. A drop in air temperature of about 8.3 deg F was measured during the 8-h test. The temperature of the pipe wall was measured to within $\pm$ 0.01 deg F by a sensor (located approximately 25 ft from the end of the line and constituting part of an array of ground and pipe-wall sensors) that had been in the ground for over two weeks before the test was conducted. Product that was 8.3 deg F warmer than the surrounding ground was circulated through the line for 2 h, and 11 h after that, the test was initiated.

The pressure test results are presented in Figure 18. The two 4-h test periods are denoted by the triangles. The additional 2.7 h of pressure data are shown in green. The pressure dropped below zero in less than 10 h, placing the line under a vacuum. The vacuum was confirmed quantitatively immediately after the pressure measurements were completed and the line was opened to atmospheric pressure through Vista's LT-100. At that time a measured volume of fuel was removed from Vista's LT-100 and sucked into the line.

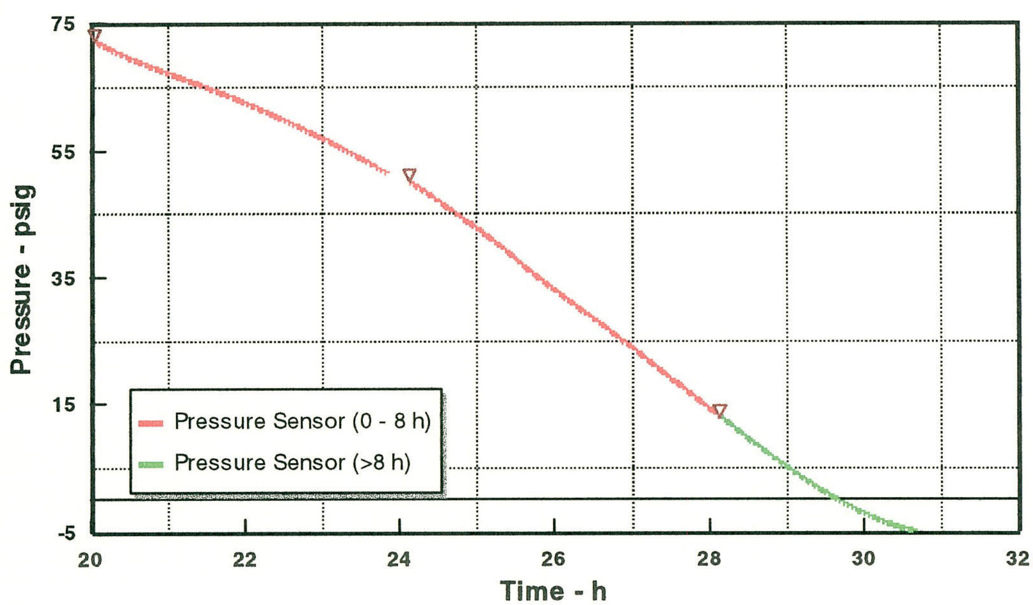

Figure 18. Results of a pressure test conducted over a 10-h period on a 1,700-gal line with no vapor and no leaks. The measured pressure data are plotted in a thick (red) line, and the symbols mark the beginning and end of the 4-h portions of the test. The product temperature decreased during the test approximately linearly at a rate of 0.06 deg F/h.

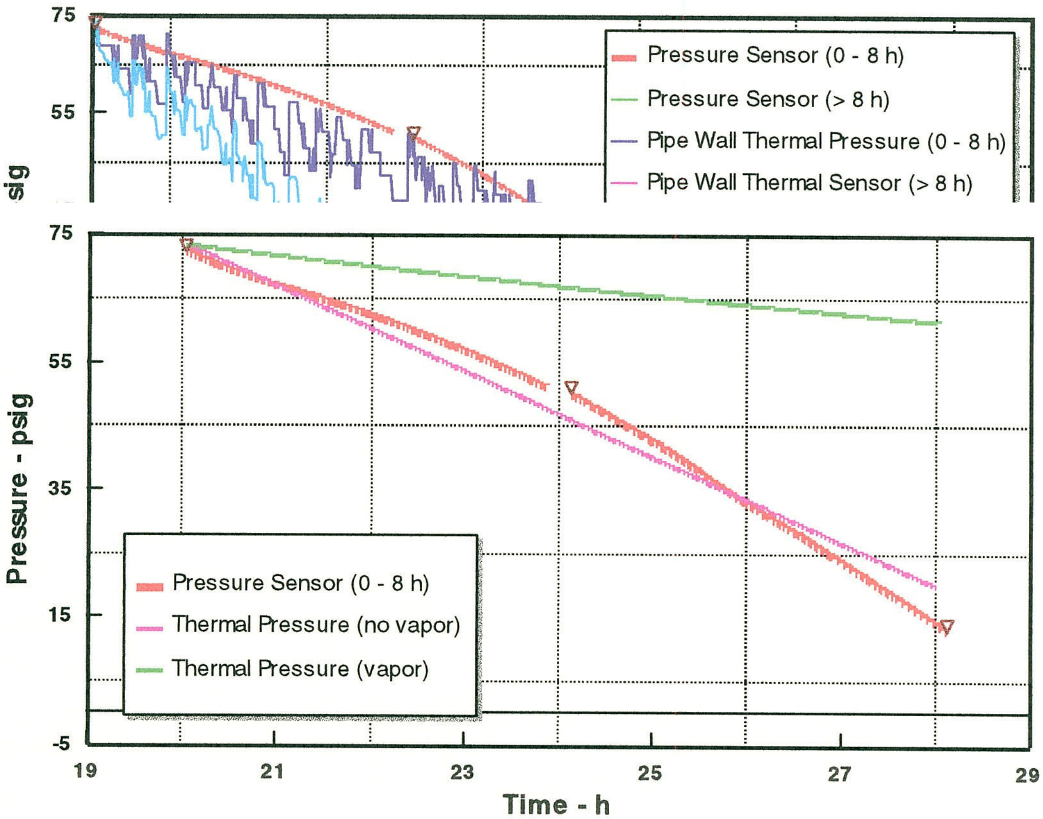

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Figure 20. Results of a pressure test conducted over a 10-h period on a 1,700-gal line with no vapor and no leaks. The results of a model calculation of pressure, assuming a linear product temperature decrease of 0.06 deg F/h with no vapor in the line (purple line) and with 0.25% vapor (green line), are superimposed on the measured pressure.

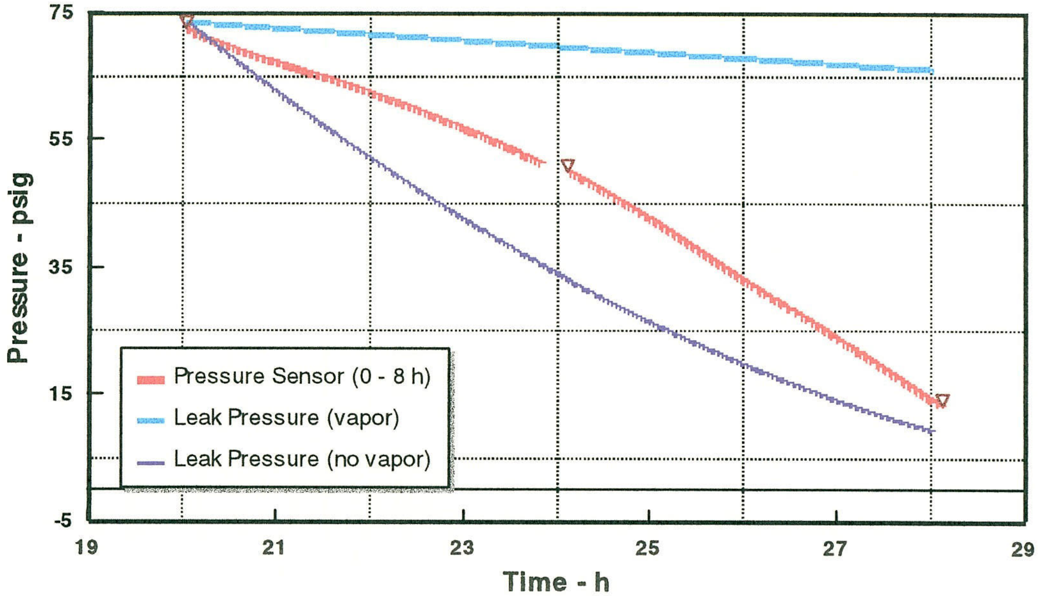

Figure 21. Results of a pressure test conducted over a 10-h period on a 1,700-gal line with no vapor and no leaks. The results of a model calculation of pressure, assuming a leak of 0.1 gal/h with no vapor in the line (blue line) and with 0.25% vapor (teal line), are superimposed on the measured pressure.

Figure 19 shows the thermally induced pressure changes estimated from the pipe-wall temperature sensor (blue curve) and from the pipe-wall and air temperature sensors (teal curve); these are scaled proportionally according to their exposure to the air for their respective contributions. The model used to make the predictions in Sections 3.2 and 3.3 was used to convert the changes in pipe-wall and air temperature to pressure changes. A decrease of approximately 0.4 deg F in the temperature of the pipe wall was observed over the 8-h test (0.06 deg F/h). This temperature drop produced a pressure drop of slightly less than 60 psi over 8 h and over 75 psi in 10 h. Since the line is known to be tight, the analysis suggests that the entire pressure drop is due to thermally induced pressure changes. The analysis further suggests that the thermally induced pressure changes are controlled by the temperature of the product in the pipe and cannot be estimated accurately by simply accounting for the thermally induced changes in the underground and aboveground sections of the pipe in proportion to the exposed volume of liquid.

In Figure 20, the thermally induced pressure changes resulting from the product temperature changes used to make the model predictions in Section 3.2.1 are superimposed on the pressure curves presented in Figure 18 without any vapor in the line (purple curve) and with 0.25% vapor in the line (green curve). The importance of knowing the volume of vapor in the line is clearly illustrated.

Figure 21 shows the pressure changes due only to a 0.1-gal/h leak (no product temperature changes) with and without vapor (teal and blue curves respectively). Again the importance of knowing the volume of vapor is illustrated.

5 Summary

The calculations presented in this paper clearly illustrate a number of significant problems associated with using a hydrostatic pressure test for detecting leaks in pressurized underground piping. The model calculations are based on well-established hydrodynamic equations that accurately predict the pressure and temperature changes in liquids and gases. The pressure test conducted at North Island is illustrative of this. The purpose of this investigation was not to develop a statistical estimate of performance. It was undertaken mainly to illustrate the significant problems that are encountered when using a hydrostatic test for detecting small leaks. The conclusions and recommendations based on these calculations are summarized below.

5.1 Conclusions

A number of conclusions can be drawn from the model calculations presented in this paper.

First, published procedures for pressure tests, while alerting the operator to many of the potential sources of error that may be encountered, give insufficient guidance on how to minimize or compensate for these sources of error. None of the standards give specific guidance on how to address the impact of vapor trapped in the line during a test or how to compensate for product temperature changes during a test.

The model calculations demonstrate that the sensitivity of a pressure measurement to a change in the volume of the product (either due to thermal expansion or contraction, or due to a leak) is highly dependent on the amount of vapor that is trapped in the line during the test. The model calculations indicate that if the volume of trapped vapor is large, the pressure changes will be small. If the volume of trapped vapor is small, the pressure changes will be large.

While each of the published pressure-test methods specifies the required accuracy of the pressure sensor or gauge used for testing, none specify the maximum allowable volume of vapor trapped in the line during a test. In most cases, it is the volume of vapor trapped in the line, rather than accuracy of the pressure gauge or sensor, that limits the test accuracy. In conjunction with a specification of a maximum allowable volume of vapor, a method of quantitatively measuring the volume of trapped vapor must be incorporated into these procedures.

The model calculations indicate that the pressure changes associated with a leak cannot be differentiated from the pressure changes associated with product temperature changes, regardless of whether or not vapor is trapped in the line. Thus, testing mistakes can easily be made, because the thermally induced pressure changes can either mask the presence of a leak (e.g., a product temperature increase during the test) or be mistaken for a leak (e.g., a product temperature decrease). The ASTM and API procedures both specify the use of a temperature sensor to compensate the pressure measurements for the thermal expansion and contraction of the product, but offer no guidance on how to effectively convert these temperature measurements to pressure so that they may be correlated with the measured pressure changes. Conversion of temperature to pressure is a two-step process requiring two additional measured values. The first is the coefficient of thermal expansion of the product in the piping. A measurement of the specific gravity of the product (and a table that lists the coefficient of thermal expansion as a function of specific gravity) is all that is required to determine the coefficient of thermal expansion with sufficient accuracy. This allows one to convert a temperature change into a volume change. In order to convert the volume change to a pressure change, the compressibility of the line under test must be measured. Since vapor trapped in the line can affect compressibility differently at different pressures, the volume of trapped vapor must be also be known. Any pressure-test procedure that attempts to compensate for product temperature changes should include a method of measuring the compressibility of the line.

Additionally, the API and ASTM procedures specify a single temperature sensor, accurate to 0.2 deg F, in contact with the pipe wall. Although not presented here, previous work by Vista Research has demonstrated in field experiments that such a temperature measurement system is inadequate to determine the average product temperature changes. The temperature data presented in Figure 19 were taken with a temperature sensor having a precision and accuracy more than 20 times better than that specified by API 1110. While these data show relatively good agreement between the measured pressure drop and the calculated thermally induced pressure drop made using only the pipe wall temperature sensor, such good agreement would not be expected under more severe thermal conditions, even with this sensor. The good agreement in Figure 19 is considered fortuitous and is more a function (1) of the benign test conditions[2] and (2) the fact that the volume of vapor in the line was measured by Vista and incorporated into the calculation of the thermally induced pressure change. The agreement would have been poor without the measurement of the volume of trapped vapor in the line or the knowledge that the large changes in air temperature during the test did not effect large pressure changes in the exposed sections of pipe.

While a leak in the line will always produce a pressure drop, product temperature changes can result in either a pressure increase or a pressure decrease. One cannot conclude that the line passes a pressure test simply because the pressure increases during a test. As stated above, thermally induced increases in pressure may be more than sufficient to offset a small leak. If temperature compensation is incorporated into a pressure test, the use of pressure relief valves to avoid over-pressurization of the line should be eliminated in favor of an alternate method of keeping the line pressure below a safe level while allowing pressure trends to be monitored even when pressure is increasing.

Second, little or no guidance is given on how to make a decision about whether or not the line is leaking. None of the published standards specify a quantitative criteria for a test, and none of the procedures indicate how to interpret the pressure changes in terms of leak rate (gallons per hour), the quantity of interest.

If the procedural additions noted above can be made, the output of a pressure test can be a temperature-compensated flow rate. In order to turn this measured flow rate into a pass/fail decision, the performance of the test method must be known. (If the test method has an accuracy of 1.0 gal/h and the system measures 5.0 gal/h in a test, then a leak in the line can be declared with a high degree of confidence. Such a decision is only obvious if the performance is known. If, however, the system measures 0.75 gal/h, no leak would be suspected. Without *a priori* knowledge of the accuracy of the system, it is impossible to determine if either of these two measurements is indicative of a leak.). The performance of the method needs to be known before one can select a *volume rate threshold* to use in determining whether or not the line is leaking. Since the accuracy of the method is dependent on the accuracy with which temperature effects are compensated for, the performance of the method, with whatever method of compensation is used,

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[2] The test shown in Figure 19 was conducted at night and was not initiated until 11 h after a small transfer of product through the line.

must be evaluated. The EPA and ASTM have published procedures for the evaluation of pipeline leak detection systems which offer guidance on how appropriate thresholds can be determined based on an empirical evaluation of a leak detection system.

The model calculations show that without compensation the effects of product temperature changes and trapped vapor will prevent a liquid pressure test from detecting small leaks. In order to get accurate results from a hydrostatic pressure test that is being used to detect leaks from an underground pipeline, one must know (measure) (1) the average product temperature change during the test, (2) the volume of trapped vapor in the line, (3) the bulk modulus, and (4) the coefficient of thermal expansion. Accurate measurements of some of these quantities are difficult to make. (For example, a measurement of temperature at only one point along the line is unlikely to result in a high degree of compensation, and operationally, it is impractical to make such measurement at many locations along a line.) Yet all are critical to the reliable application of the pressure test method to the detection of leaks in underground piping.

5.2 Recommendations

The use of the hydrostatic or liquid pressure test described in the current standards is not a good way to routinely check bulk piping for leaks. The results are ambiguous and not quantitative. Even with significant development and field testing, it is unlikely that a robust and practical methodology could be developed. This development would be an expensive and time-consuming endeavor. Fortunately, there are a number of different kinds of commercially available methods that are not affected by the problems associated with a liquid pressure test and that have a much higher level of performance than can be achieved with a hydrostatic pressure test. These methods are in compliance with the UST regulations [9].

Vista's LT-100 system, which has recently been introduced into the marketplace, was developed specifically to test bulk piping. The performance of the LT-100 has been evaluated by a third party according to EPA and ASTM standard procedures and practices [1,2]. The LT-100 is capable of detecting leaks of 0.1 gal/h (for compliance with annual tightness test) or 0.2 gal/h (for compliance with monthly monitoring test) with a probability of detection better than 95% and a probability of false alarm less than 5%, and has been certified by the National Work Group on Leak Detection. The LT-100 will easily outperform a hydrostatic pressure test, even one that completely and effectively addresses all of the problems described in this paper.

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Appendix A

Modeling Results
for an 8-h Pressure Test on a 3,133-Gal Pipe

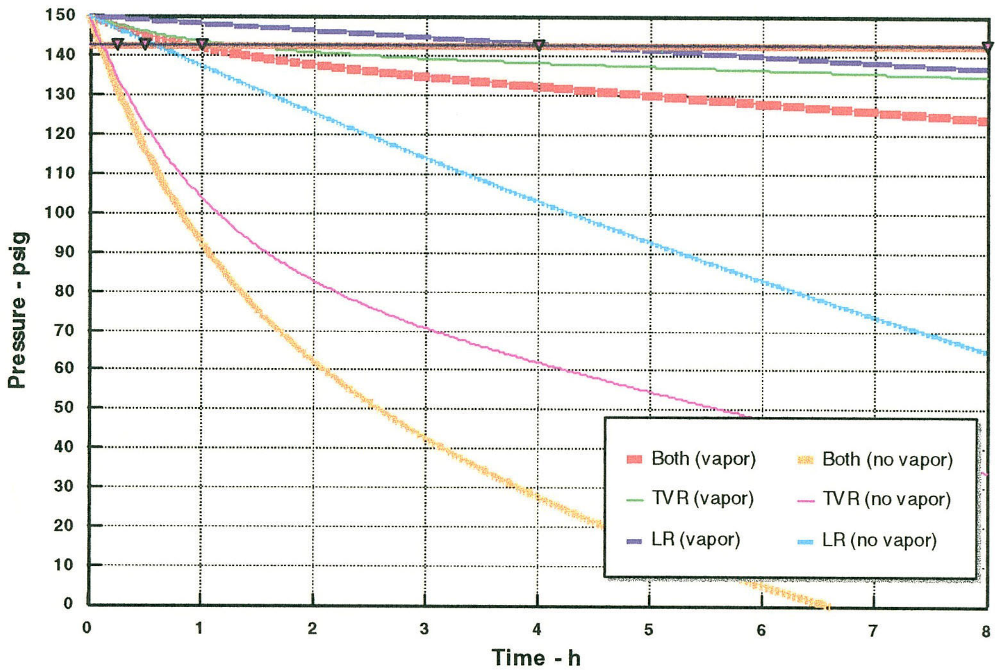

Figure A-1. Results for pressure tests up to 8 h in duration on a 3,133-gal line with decreasing product temperature and a leak of 0.2 gal/h, with and without the presence of trapped vapor.

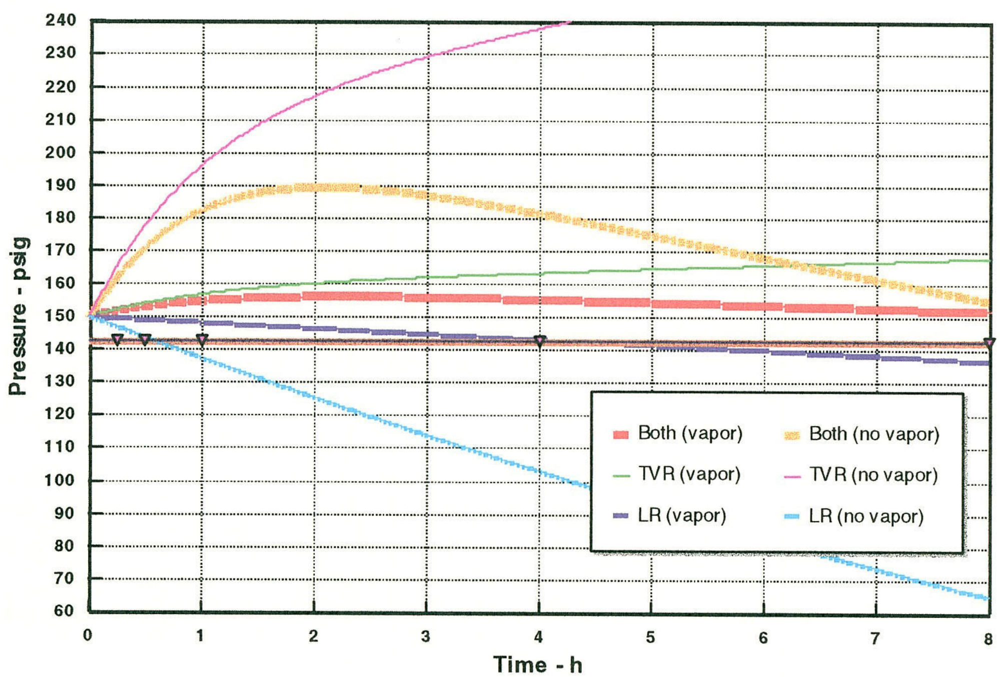

Figure A-2. Results for pressure tests up to 8 h in duration on a 3,133-gal line with increasing product temperature and a leak of 0.2 gal/h, with and without the presence of trapped vapor.

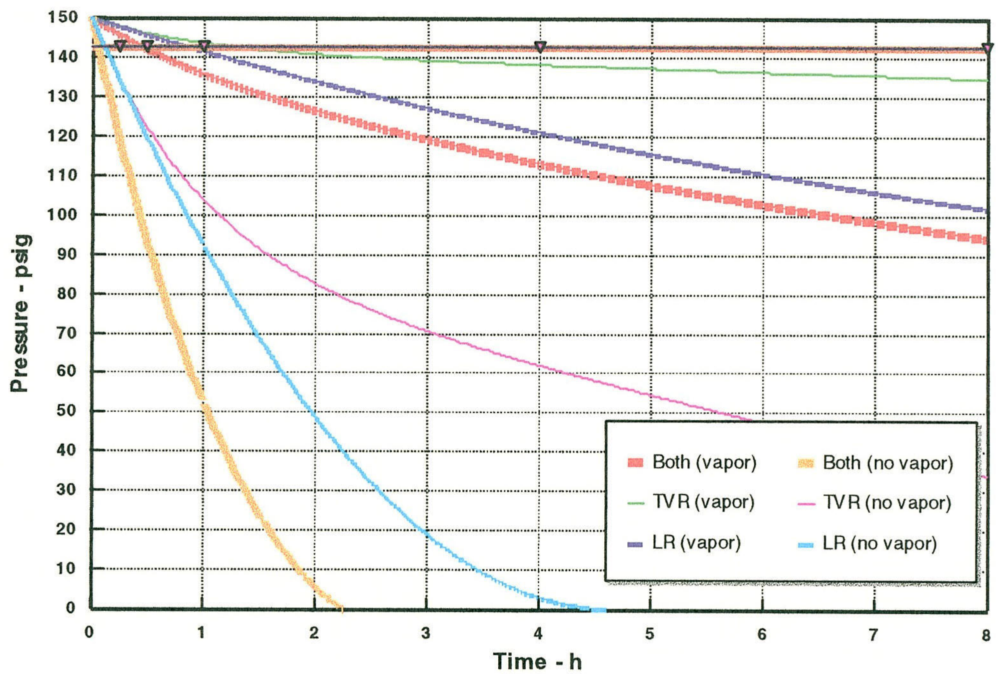

Figure A-3. Results for pressure tests up to 8 h in duration on a 3,133-gal line with decreasing product temperature and a leak of 1.0 gal/h, with and without the presence of trapped vapor.

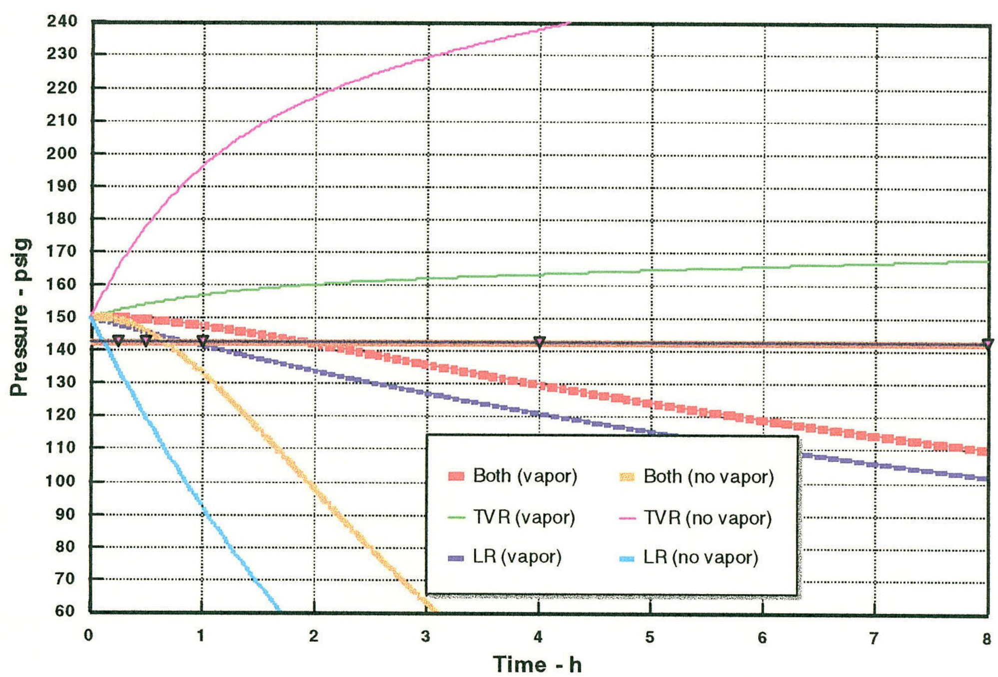

Figure A-4. Results for pressure tests up to 8 h in duration on a 3,133-gal line with increasing product temperature and a leak of 1.0 gal/h, with and without the presence of trapped vapor.

Appendix B

Modeling Results
for an 8-h Pressure Test on a 12,533-Gal Pipe

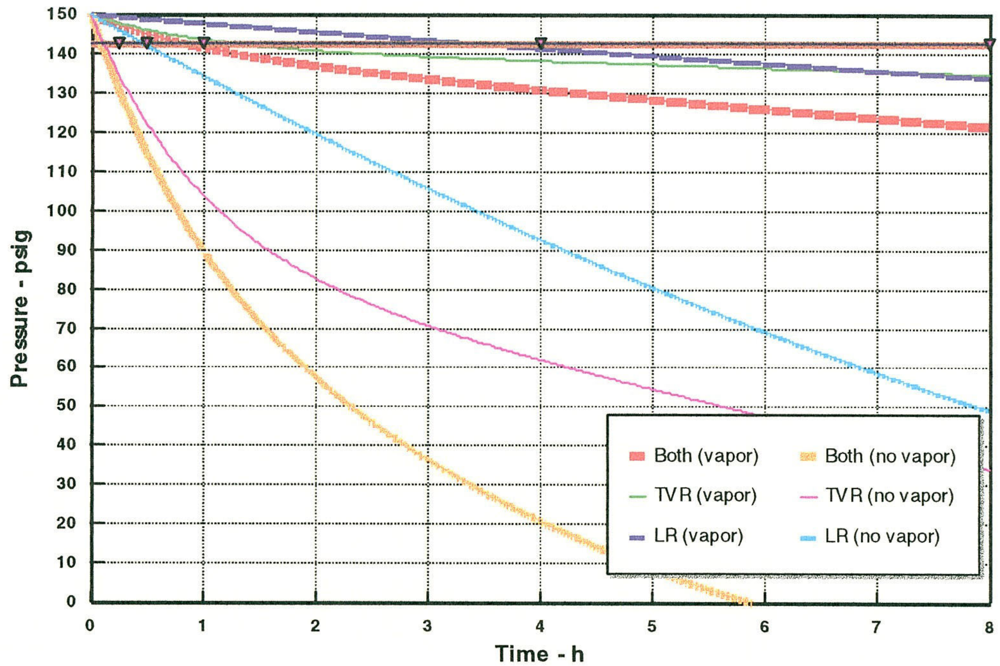

Figure B-1. Results for pressure tests up to 8 h in duration on a 12,533-gal line with decreasing product temperature and a leak of 1.0 gal/h, with and without the presence of trapped vapor.

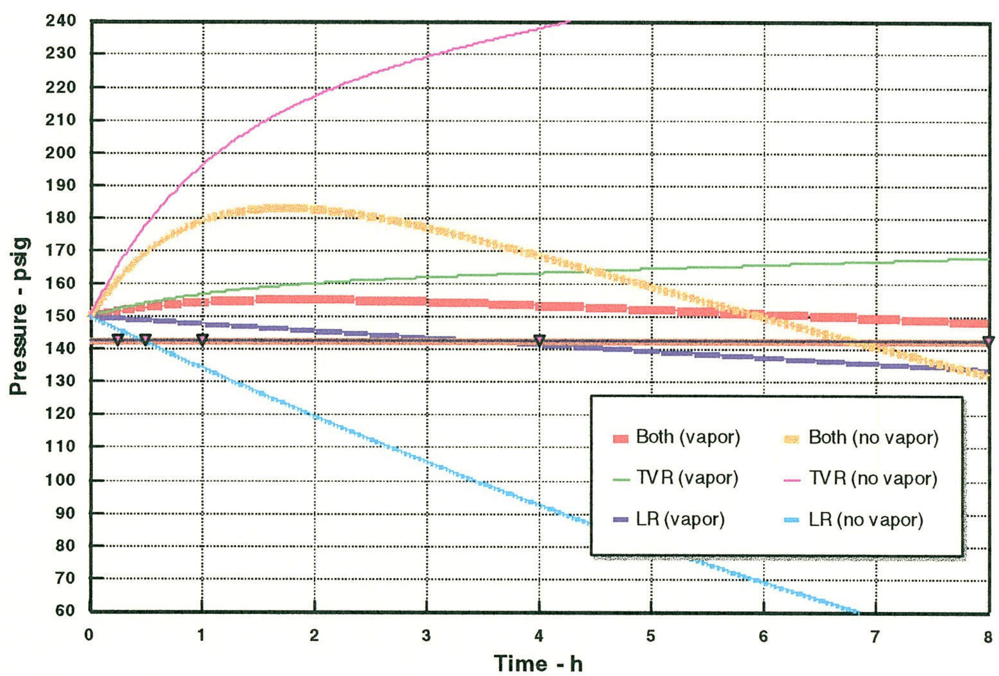

Figure B-2. Results for pressure tests up to 8 h in duration on a 12,533-gal line with increasing product temperature and a leak of 1.0 gal/h, with and without the presence of trapped vapor.