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GUIDANCE DOCUMENT ON MECHANICAL INTEGRITY TESTING OF INJECTION WELLS

EPA CONTRACT NO.
68-01-5971

Submitted to:
Dr. Jentai Yang
Office of Drinking Water

Mr. David Zelnick
Contract Operations

Prepared for:
U. S. Environmental Protection Agency

Prepared by:
Geraghty & Miller, Inc.
April 30, 1982

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GUIDANCE DOCUMENT ON MECHANICAL INTEGRITY TESTING OF INJECTION WELLS

I. INTRODUCTION

1. Purpose of This Document

The purpose of this document is to impart to managers who are not acquainted with the technical aspects of construction and operation of injection wells, the knowledge to enable them to implement the rules and regulations in that section of the Underground Injection Control Regulations regarding the mechanical integrity of injection wells. Beginning with the definition of mechanical integrity as expressed in the regulations, this document explains the theory and practice of the various tests used in determining the mechanical integrity of an injection well.

2. The Meaning of Mechanical Integrity

Injection wells can convey fluids that may be regarded as potentially detrimental to drinking-water quality. It is important to assure that injected fluids do not contaminate ground water used for drinking or having the potential for such use. This assurance is gained during the construction of an injection well by: (1) using well casings, tubings, and packers that do not leak and, (2) by properly cementing the annulus between the casing and formation, thus precluding the movement of fluids through the well annulus. Figure 1 illustrates these potential threats. If a well does not have these defects, it is said to have mechanical integrity.

Section 146.08 of the State Underground Injection Control Program (40 CFR Part 146, Federal Register, Volume 45, No. 123, June 24 1980) states that a well has mechanical integrity if: (1) there is no significant leak in the casing, tubing, or packer; and (2) there is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore. According to Section 146.08, the absence of leaks must be demonstrated by either performing a pressure test with liquid or gas or by monitoring the annulus pressure. Leaks or fluid movement that pertain to the second criterion must be demonstrated absent by a temperature or noise log. The mechanical integrity of injection wells associated with oil and gas production (Class III) may be demonstrated by well records indicating the presence of adequate cement to prevent fluid movement in the well annulus. Exception to rules governing both types of leaks may be authorized by the Administrator of the EPA.

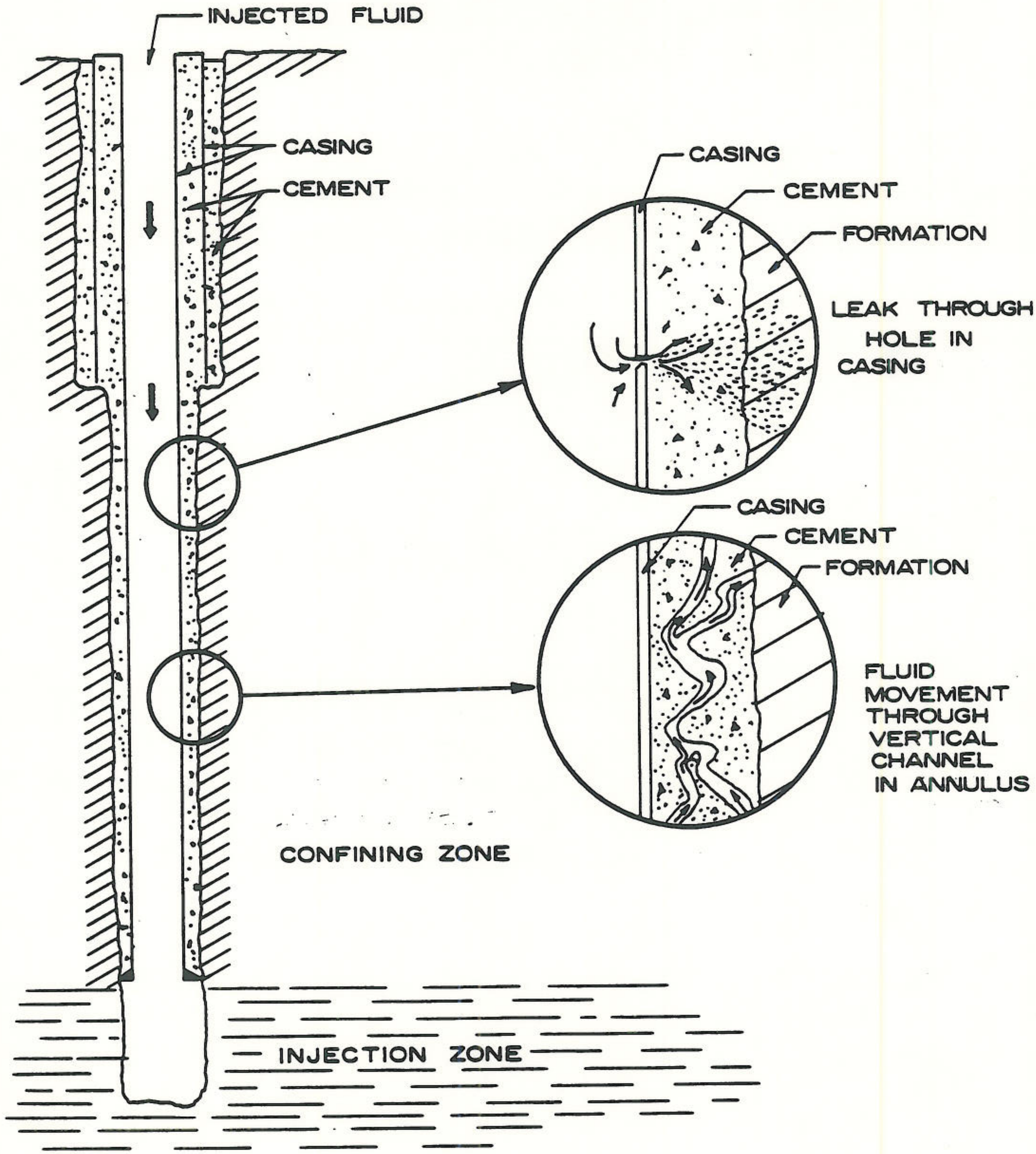


Figure 1

INJECTION WELL WITH A LEAK THROUGH THE CASING AND FLUID MOVEMENT THROUGH A VERTICAL CHANNEL

3. Classification of Injection Wells

Section 146.05 defines five classes of injection wells on the basis of use and the relationship of the injection zone to underground sources of drinking water. A definition of each class of well, and a description of wells in Classes I, II, and III with examples of typical construction are presented below.

a. Class I: Class I wells include: (1) wells used by generators of hazardous wastes or owners or operators of hazardous waste management facilities to inject hazardous waste, other than Class IV wells, and (2) other industrial and municipal disposal wells which inject fluids beneath the lowermost formation containing drinking water within one-quarter mile of the well.

Class I injection wells include basically two types, as illustrated on Figure 2. That referred to as Type A is the most common type consisting of one or more strings of grouted casing, tubing, and packer. Type B, common to municipal injection well systems, consists simply of several strings of grouted casing and no tubing and packer.

b. Class II: Class II includes wells which inject fluids: (1) which are brought to the surface in connection with conventional oil or natural gas production, (2) for enhanced recovery of oil or natural gas, and (3) for storage of hydrocarbons which are liquids at standard temperature and pressure.

Wells in Class II have no typical design; however, those recently constructed are generally fitted with tubing and packer. Construction characteristics vary according to function, depth, location, age, and other factors.

c. Class III: Class III wells are those that inject fluids in order to extract minerals or energy, including but not limited to those for: (1) mining of sulfur by the Frasch process, (2) solution mining of minerals, (3) in-situ combustion of fossil fuels, and (4) recovery of geothermal energy to produce electric power.

In 1980 there were approximately 7,830 Class III injection wells that would be subject to UIC regulations. Of these, about 500 exist for the purpose of sulfur recovery by solution mining, and 6,300 for in-situ leaching for uranium recovery. The remainder are used in recovery of copper and other metals as well as for geothermal energy. Typical construction details of each type of well in Class III are described below.

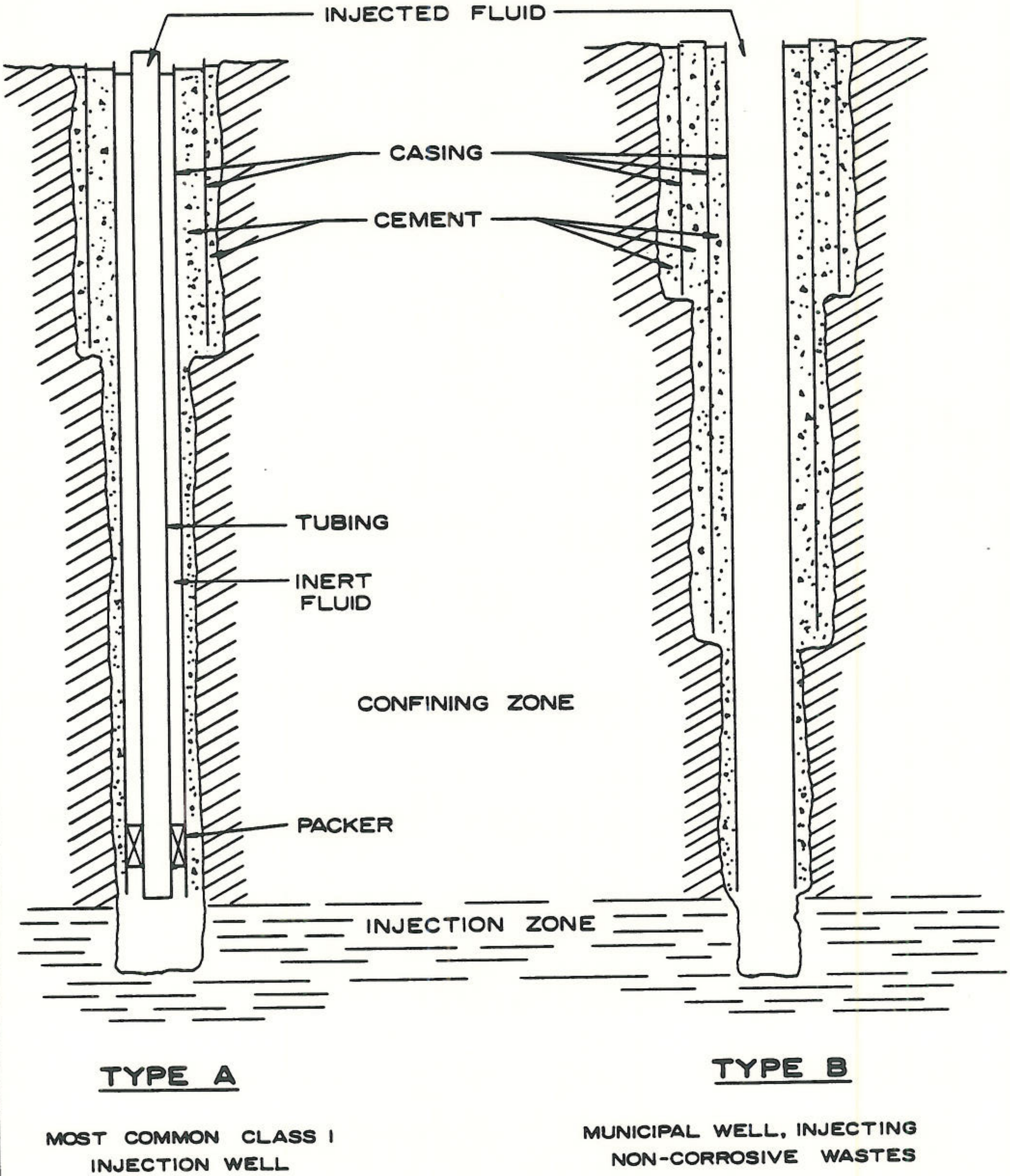


Figure 2

CLASS 1 INJECTION WELLS

i. Sulfur Mining Wells

Sulfur contained in the lower part of the limestone cap rock overlying salt domes or in bedded salt strata is mined by the Frasch process in the Gulf Coast area of Texas and Louisiana and in west Texas. In the Frasch process, injection of fluids and recovery of sulfur take place in the same well. Figure 3 shows the design of a sulfur well with cemented casing that is used in parts of Louisiana. High pressure from steam injection causes the sulfur to dissolve and then rise in a small-diameter inner casing, from which it is pumped to the surface by air lift.

In typical Frasch sulfur wells in Texas, an outer casing (8- or 10-inch-diameter) is set into the top of the cap rock, and the overlying formations are permitted to collapse around the uncemented casing. The depth of the injection zone ranges from about 400 to 2100 feet. Six-inch casing, with two perforated zones near the bottom, is set inside the outer casing to the base of the sulfur-bearing cap rock. The upper perforations, for steam injection, are separated from the lower perforations and from a three-inch production casing by means of a packer.

ii. Salt Solution Wells

Solution mining of salt is accomplished by the injection of water and recovery of brine through wells. Solution mining is practiced to depths ranging from several hundred feet to about 10,000 feet. Well designs are adapted to the particular salt body to be mined and differ widely. In thick salt beds or in salt domes, injection and withdrawal are commonly through single, multiple-cased wells (Figure 4), with injection into an inner casing and return flow through the annulus. The inner casing or tubing may be movable to permit variable-point injection. Thin-bedded salt deposits in the mid-continental and northeastern part of the country are commonly mined by the use of one or more separate injection and recovery wells.

iii. In-Situ Leaching of Uranium

Uranium deposits suitable for mining by in-situ leaching are found in sand and sandstone in Texas and to a lesser extent in Wyoming. These deposits must be below the water-table and in well-confined strata. Uranium is leached by the injection of dilute alkaline or acid solutions (lixiviants), in combination with a chemical oxidant, at depths from 300 to 2000 feet. Separate wells are used for extraction.

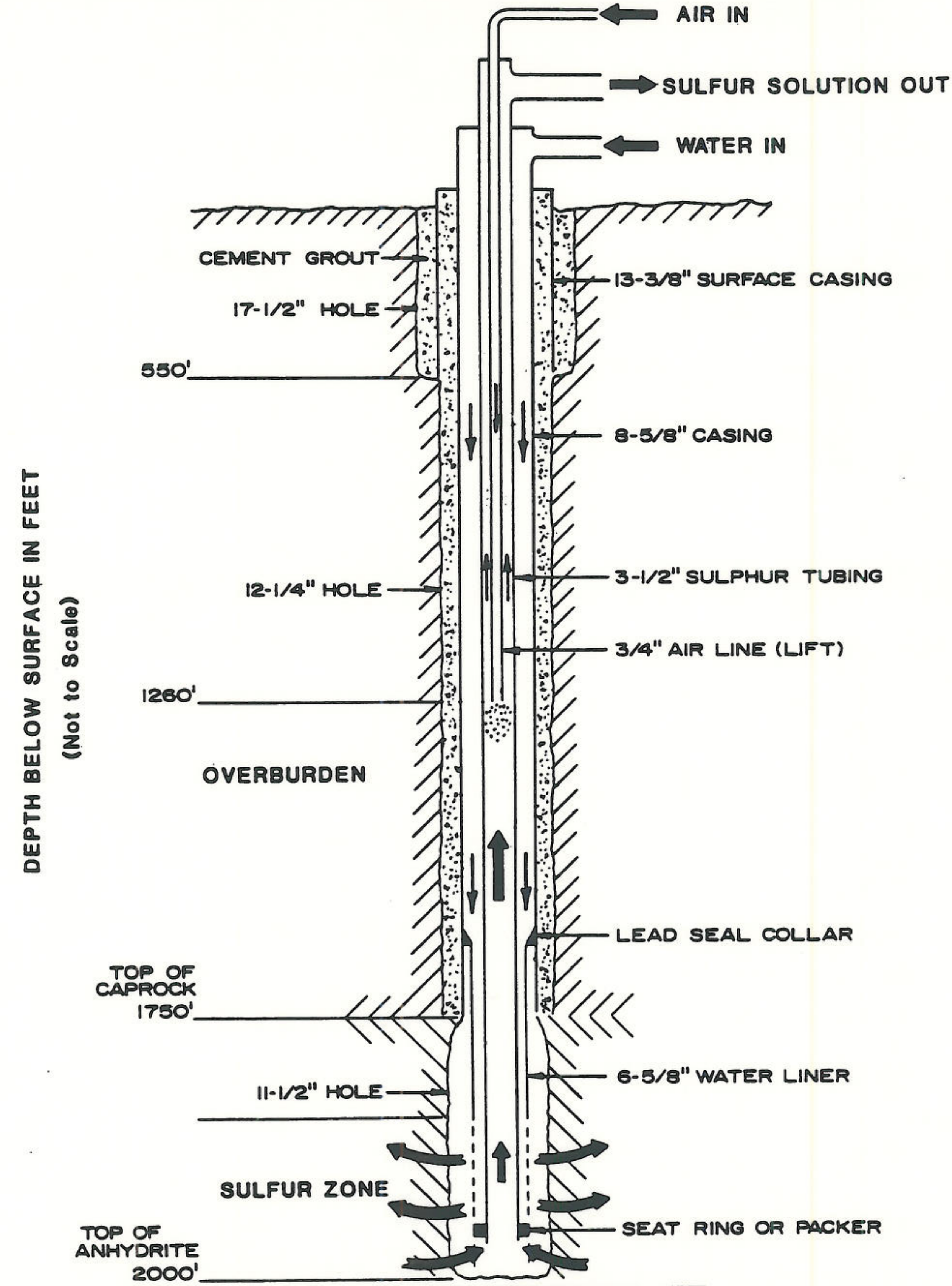


Figure 3

A FRASCH SULFUR WELL IN LOUISIANA

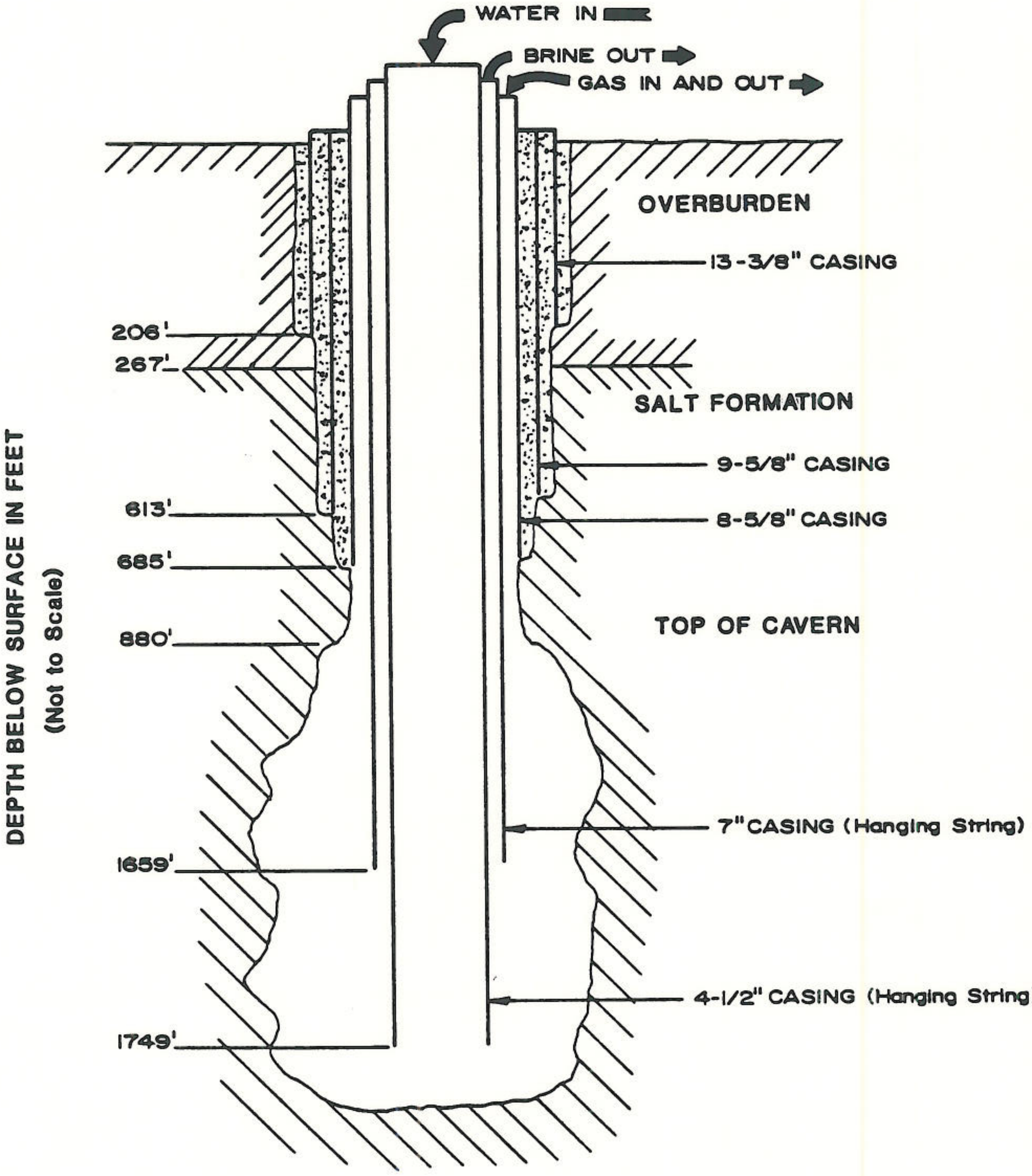


Figure 4

A SALT SOLUTION-MINING WELL
SHOWING MULTIPLE CASINGS AND CEMENT

A typical well consists of a single-wall cemented casing and well screen, slotted casing, or perforated pipe. The casing material may be PVC, steel, or fiberglass. Various patterns are used in the spacing of injection and production wells, the function of which may be reversed.

iv. In-Situ Leaching of Copper

In-situ leaching of copper is practiced in igneous ore bodies, or in worked-out mines where the ore is not of sufficient grade to be extracted by conventional methods. A dilute sulfuric acid solution or water is injected into the ore deposit through wells and the leachate is recovered through other wells, mine workings, or other openings. Much of the work to date is experimental and solution mining of copper is not widely used.

No single construction method is used for boreholes that inject copper-leaching solutions. Where leaching solutions are introduced into previously mined, caved, or blasted ore bodies, injection wells commonly are shallow, cased or uncased boreholes into which the fluids enter by gravity flow.

v. In-Situ Combustion of Coal, Oil Shale, and Tar Sands

In-situ combustion of fossil fuels is presently being evaluated as an environmentally preferable mode of mineral extraction, but is not developed beyond the experimental stage. Wells that may be used for air injection, ignition, and/or recovery, are experimental in both design and scale. It is not possible at this time to consider typical injection well designs in this category.

vi. Geothermal Energy

The principal uses of injection wells associated with geothermal facilities are to dispose of brines brought to the surface from underground zones of high temperature and to dispose of brine and condensates from generating plants. The only facility in the United States presently producing electricity and utilizing injection wells continuously is in northern California, where nine injection wells return small amounts of condensate back to the producing formation by gravity flow. The wells have multiple casing and cement seals. Because of the early stage of development of geothermal resources for electrical generation, there are no injection well designs in this category that may be considered typical. Injection wells used in the development of geothermal energy and not for electrical generation, belong to Class V and are not considered here.

d. Class IV: Class IV wells are used by generators of hazardous waste or of radioactive wastes, by owners or operators of hazardous waste management facilities, or by owners or operators of radioactive waste disposal sites to dispose of hazardous wastes or radioactive wastes into or above a formation which within one-quarter mile of the well contains an underground source of drinking water. Wells of this class are not addressed in this document.

e. Class V: Class V injection wells are those not specifically included in Classes I, II, III, or IV. Some types of wells that belong to this category are air-conditioning return-flow wells, cesspools, drainage wells, recharge wells, salt-water intrusion barrier wells, sand back-fill wells, septic system wells, subsidence control wells, wells used for hydrocarbon storage, geothermal wells used in heating and aquaculture, and nuclear disposal wells. These wells, like those of Class IV, are not addressed in this document.

4. <u>The Distinction Among Tests Required in Section 146.08 to Detect the Presence and the Location of Leaks and Fluid Movement</u>

Pressure tests or the monitoring of annulus pressure can detect the presence of leaks in the casing, tubing, or packer, but generally yield no information on the location of such leaks unless specific zones are isolated. The temperature log and noise log not only can detect the presence of leaks, but also fluid movement through vertical channels adjacent to the well bore. They also can be used to locate such failures. These logs, however, cannot be used to distinguish between a leak and fluid movement behind the casing without a pressure test or monitoring of annulus pressure.

It is apparent from the foregoing that there are significant and basic differences amount the types of tests and their results. In addition to the required geophysical logs, there are many others that may provide indications of various types of well failures. These include the radioactive tracer, cement bond, caliper, and casing condition logs. These may be considered supplementary (to be employed when ambiguity results from the required logs) or as alternatives to the required logs if approved in writing by the EPA Administrator. A summary of the applicability of the required and other useful tests is presented as Table 1. The characteristics of each test, its applicability, interpretation, and limitations, are discussed below.

II. PRESSURE TESTS AND MONITORING OF ANNULUS PRESSURE

1. <u>Applicability Related to Well Construction</u>

Either a pressure test or monitoring of the annulus pressure may be used to detect the presence of leaks in the casing, tubing, or packer of an injection well. These tests are applicable to all types of casing,

TABLE 1

APPLICABILITY OF TESTS THAT MAY BE USED FOR MECHANICAL INTEGRITY VERIFICATION

TEST	CAUSE OF INJECTION WELL FAILURE				APPLICABILITY TO TYPES OF CASING	
	LEAKS IN CASING, TUBING OR PACKER		FLUID MOVEMENT BEHIND CASING		METAL	PVC AND SIMILAR SYNTHETICS
	Presence	Location	Presence	Location		
Pressure Test	yes	no (1)	no	no	yes	yes
Monitor Annulus Pressure	yes	no	no	no	yes	yes
Temperature Log	yes	yes	yes	yes	yes	yes
Noise Log	yes	yes	yes	yes	yes	yes (2)
Radioactive Tracer Log (4)	yes	yes	yes (5)	yes (5)	yes	yes
Cement Bond Log (4)	no (3)	no (3)	yes (3)	yes (3)	yes	yes (2)
Caliper Log (4)	no (3)	no (3)	no (3)	no (3)	yes	yes
Casing Condition Log (4)	yes (3)	yes (3)	yes (3)	yes (3)	yes	no

(1) can be "yes", if test is staged
(2) log response may be somewhat dampened
(3) may indicate potential failure site
(4) may be used with approval of EPA Administrator
(5) only if access by tracer can be gained through the casing or beneath casing shoe

although consideration of casing strength may be necessary where PVC is used, especially at higher temperatures. The pressure test can be conducted in three ways, depending on the well's construction details. Monitoring of the annulus for change in pressure, however, is only applicable to the well configuration having tubing and packer. The three pressure test configurations and one monitoring configuration are illustrated in Figure 5 - A, B, and C.

Configuration A, a cased and grouted well sealed at the bottom (by a retrievable plug or packer) and top, shows a test of the casing only. The lack of a tubing or permanent packer precludes other pressure testing. Likewise, the lack of an annulus precludes pressure monitoring as an alternative determinant of well integrity.

Configuration B, a cased and grouted well fitted with tubing and packer and sealed at the top, shows a test of the casing, tubing, and packer. This test cannot distinguish which of the three components of the well is leaking. Pressure monitoring of the annulus between the tubing and casing could also be conducted as an alternative to pressure testing.

Configuration C is a cased and grouted well fitted with tubing, packer, and seating nipple. The presence of the seating nipple at the base of the tubing allows pressure testing of the tubing exclusively, in addition to the pressure test and pressure monitoring as possible in Configration B.

2. Procedures and Interpretation

Both industry and regulatory agencies use and/or require pressure testing of the various injection well components as a means of determining the presence of leaks. Pressure tests are relatively inexpensive and easy to perform in both old and new injection wells; they also produce results that are simple and easy to interpret. For these reasons, pressure testing of the casing, tubing, and packer is considered the principal and most reliable means of determining mechanical integrity.

Typically, pressure tests have been performed at pressures equivalent to 125 percent of the design operating pressure for periods that range from 5 to 30 minutes. Minimum pressure-test criteria for well integrity should be the maintenance of 125 percent of the peak operating pressure for a period of 30 minutes. The well is determined to be sound if the pressure stabilizes at a point equal to or greater than the peak operating pressure and does not fall below that value. If the pressure falls below the peak value, the well is determined to be unsound; a significant leak is considered to exist, and remedial measures are taken.

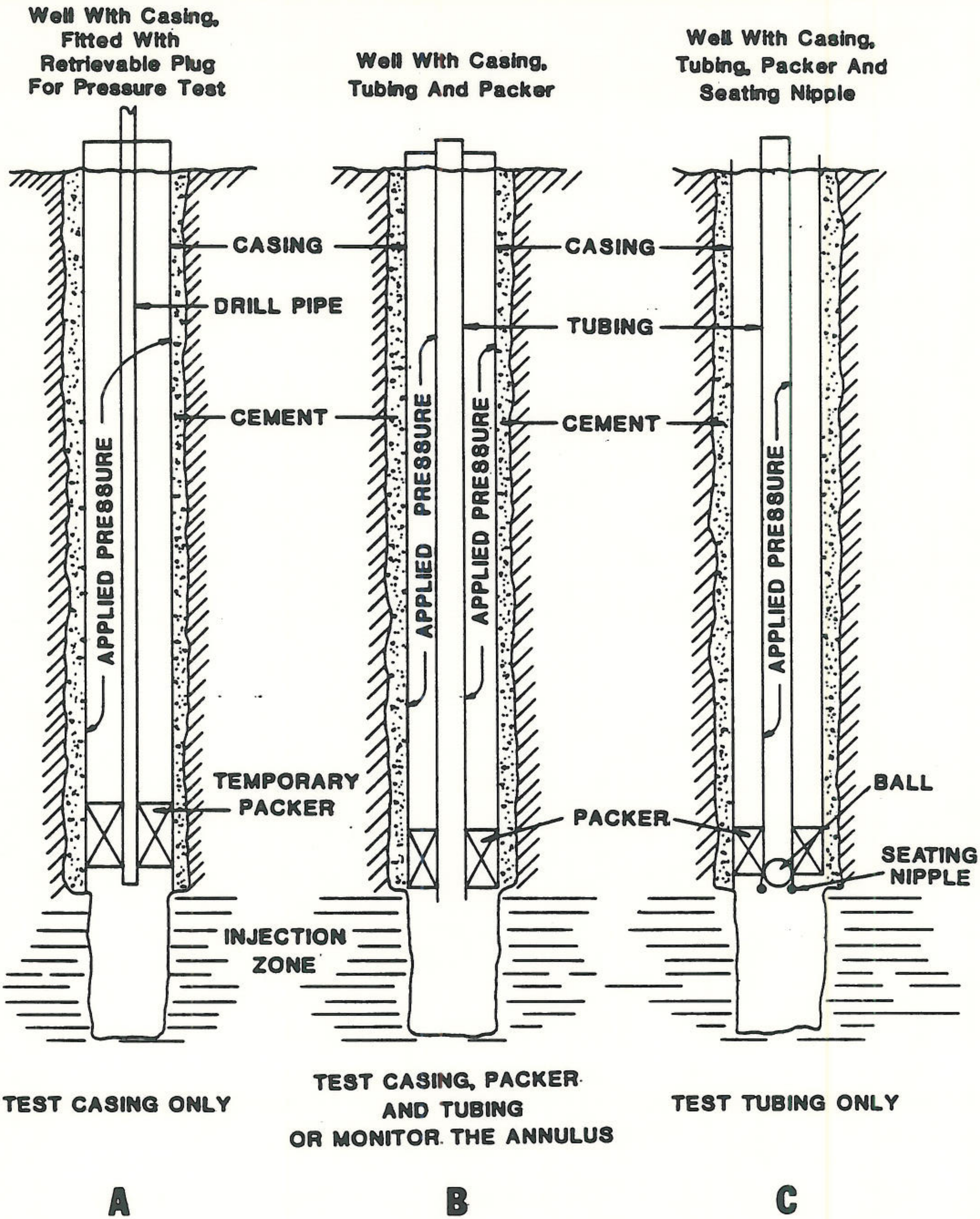


Figure 5
THREE WELL CONFIGURATIONS ILLUSTRATING THE THREE MODES OF PRESSURE TESTING, AND THE MONITORING OF THE ANNULUS PRESSURE

Pressure-test procedures are significantly different between injection wells that are new or under construction and those that exist. Test procedures are designed to take best advantage of the unique features of each type of well.

In a new well, the inner casing is usually pressure tested after it has been cemented and before the casing shoe is drilled out. At that time, cement is present at the bottom of the casing so that the casing is sealed. A seal at the top can be effected by using a blow-out preventer or other easily adapted wellhead seal. Usually the pipe is filled with fluid and pressure is applied using the rig mud pump (rig mud pumps usually can be utilized to supply pressures up to 1000 psi; for greater pressures, cement pumping equipment is generally used).

If the casing does not hold pressure in accordance with accepted criteria, an attempt to locate the leak using a noise log or temperature log may be used. Based on these findings, repairs to the casing may be made. If the casing holds pressure, then the next tests for mechanical integrity can be undertaken.

In an old well without tubing or packer, the bottom of the inner casing can be sealed with a retrievable plug (bridge plugs or packers are used) prior to testing. Such plugs are available to fit casings having inside diameters from 1.87 to 13.37 inches. The same sources for pressure noted above can be utilized. Plugs should not be set in old or corroded steel casings that may be prone to rupture. Casing condition logs described below are useful in determining the competency of a casing to withstand packer pressures. In the case of PVC casings or those of similar synthetics, a comparison between the rupture pressure of the casing and the packer pressure should be made prior to testing to insure that casing strength is not exceeded. The temperature should be considered in this comparison.

In old wells with tubing but no packer, the outside casing is tested after the tubing has been pulled and a retrievable plug set. If successful, the tubing is reinstalled and tested in the well. Usually, the tubing is fitted with a seating nipple at the bottom. The tubing is then sealed at the top and a pressure test is performed. Following a successful test, the ball is "reversed out" and the well is ready for service.

Both new and old wells with tubing and packer are tested by pressurization. The most efficient step-wise procedure for testing such a well is graphically described in Table 2. It is assumed in this procedure that work by a geophysical logging service company is less expensive than that of a service company capable of setting a retrievable packer at the bottom of the casing. This would generally be true, especially considering that geophysical logging services are required at the well site in testing for fluid movement in vertical channels in the

TABLE 2

PROCEDURE FOR TESTING THE MECHANICAL INTEGRITY
OF AN INJECTION WELL HAVING TUBING AND PACKER

STEP NUMBER	PROCEDURAL STEP
1	CHECK FOR LEAK IN CASING, TUBING, OR PACKER
2	Pressurize Annulus
3	Annulus Pressure Adequate? Yes, go to 20
4	CHECK FOR LEAK IN TUBING
5	Pressurize Tubing with Seating Nipple and Ball
6	Tubing Pressure Adequate? Yes, go to 10
7	LOCATE LEAK IN TUBING
8	Run Noise or Temperature Log in Tubing with Pressurized Annulus
9	Fix Tubing Leak
10	CHECK FOR LEAK IN CASING OR PACKER
11	Pressurize Annulus
12	Annulus Pressure Adequate? Yes, go to 20
13	CHECK FOR LEAK IN CASING
14	Remove Tubing, Install Bridge Plug, Pressurize Casing
15	Casing Pressure Adequate? Yes, go to 19
16	LOCATE CASING LEAK
17	Run Noise or Temperature Log with Pressure in Casing
18	Fix Casing Leak
19	Fix Packer
20	CHECK FOR FLUID MOVEMENT IN BOREHOLE ANNULUS
21	Run Noise and Temperature Log
22	Leak Detected? No, go to 24
23	Repair Fluid Movement Failure
24	MECHANICAL INTEGRITY CONFIRMED

well bore, the second and mandatory test for mechanical integrity of injection wells.

Pressure tests are generally conducted on the entire length of casing or tubing, but may be staged at vaious well depths if warranted. Suspicion of two or more independent leaks at different depths may justify staged testing. Such testing has the potential to locate, in addition to detect, a leak. In this procedure, a bridge plug and packer are set on opposite sides of the suspected leak. This procedure is complicated and time consuming, but may be considered in the event a leak cannot be located because of constraints on geophysical logging.

In some instances, a reverse type of test is used to determine casing integrity of a new or used well. In this test, fluid is removed from the casing. This must be done cautiously in order to prevent casing collapse. For deep wells, the evacuation is staged using a bridge plug and packer. The space between the plug and packer is evacuated and then observed to determine whether or not fluid enters. This test is called a dry test and will work only in those portions of the casing opposite formations that are saturated with fluids and are somewhat permeable.

The alternative to the pressure test in the determining leaks is the monitoring of annulus pressure in the injection well. This can be used only on those wells constructed with tubing and packer. In this arrangement, the pressure in the annulus should be held 10 psi above atmospheric pressure and retained there. This pressure would then be monitored by periodic checks or by continuous recording, along with the injection pressure. A leak in the casing, tubing, or packer is indicated by a change in the annulus pressure, either higher or lower. A leak in the tubing or packer would probably result in a higher pressure due to the transfer of the injection pressure. A leak in the casing, on the other hand, would probably result in a lower pressure.

It is possible that monitoring of annulus pressure would not detect the presence of a leak or leaks that may be in equilibrium with the pressure imposed on the annulus. To eliminate this possibility, it is desirable to periodically vary the pressure applied to the annulus. In effect, this procedure constitutes a long-term pressure test. By varying the annulus pressure, the presence of leaks at equilibrium at any one pressure will become apparent. Pressure variations need not be more than a few psi.

If the injected fluid varies significantly in temperature, either seasonally or with another factor, fluctuations in the annulus pressure may occur in response to thermal expansion or contraction of the fluid in the annulus. If this influence on the annulus pressure is excessive, it may be necessary to monitor the temperature of the injected fluid in order to be sure that pressure changes are solely due to changes in the temperature and not due to leaks.

3. Costs for Pressure Tests and Monitoring

Costs for pressure testing a well are directly related to its construction. For a new well or an existing one equipped with tubing and packer, the test is simple and the cost is not high. In a new well, a pressure test is performed on the inner casing after it has been cemented in place, and before the cement at the bottom of the casing has been drilled out. For pressure testing the casing with the drilling rig, the estimated cost is $400. If a cement pump is required, the cost is estimated to be $800 to $1,200, depending on the time the equipment is on location.

A similar cost would be incurred in performing a pressure test on an existing well equipped with a tubing and packer. Usually this can be done by operating personnel, using their own or rental equipment.

Greater costs will be incurred performing a pressure test on a well with no tubing or packer, or only tubing. In the case of a well with tubing, a rig will have to be used to pull the tubing and reset it. For a well with no tubing or packer, a rig will be used to set and pull a retrievable plug. In most cases, a workover rig rather than a standard rig is employed, as it is designed specifically for these operations.

Determination of the cost of performing pressure tests with greater accuracy than the estimates above is complicated by the fact that a "typical" well does not exist. Casing depths and diameters vary, as do the depths of the tubing settings. The condition of the well is often a controlling factor in how long it takes to do a particular task. Companies doing such work charge according to complicated schedules that incorporate factors of time, distance to the well, standby charges, working depths, and the size of the tools to be used. In the event the equipment must be used in a "hostile environment" (abnormal pressure, high temperatures, or a corrosive fluid), additional charges are billed. Consequently, because of the numerous variables that would be considered, it is impossible to arrive at a precise cost for pressure testing.

Some idea of the range in costs for a pressure test is obtained by setting up arbitrary examples assuming a range of well depths, distances to the well, time required to pull tubing, set and remove a retrievable plug, and reset the tubing. The following examples assume a 300-mile round trip to the well, well depths from 2,000 to 6,000 feet (80 percent of injections wells are included in this depth range), rig time at $125 per hour, and mileage charges of $1.50 per mile. It also is assumed that there are delays no greater than 8 hours (accounted as rig time) due to unanicipated conditions such as site work to make the well more accessible, problems in removing well-head equipment prior to entry, etc. Costs due to lost production time, use of alterative waste disposal facilities, in-house administration and engineering associated with any testing are not included. The same assumptions are used to develop costs for performing a test on a well with no tubing, but for which a rig is required. In this case, no rig time is needed for pulling and resetting tubing.

Costs for performing tests under the above assumptions are listed below (estimates are in terms of 1980 dollars and rounded to the nearest $100).

Working Depth (feet)	Estimated Costs With Tubing & Packer	Estimated Costs Without Tubing & Packer
2,000	$ 6,400	$ 5,600
3,000	$ 7,400	$ 6,000
4,000	$ 8,300	$ 6,400
5,000	$ 9,200	$ 6,900
6,000	$10,200	$ 7,400

The cost of continuous monitoring of the annulus pressure is for instrumentation and personnel. A recording pressure gauge or water-level recorder can vary in cost from one to several thousands of dollars, depending on the features. Personnel costs would depend upon the needed frequency of maintenance and repair of the instrument. Because of the high degree of variability in the costs associated with continuous monitoring, no estimates are made.

The cost of non-continous monitoring pressure in the annulus between the tubing and casing is almost exclusively for personnel. The only equipment cost is that of an accurate pressure gauge or manometer, which should amount to less than $100. If, for example, it is assumed that a weekly reading of the annulus pressure is made by an injection well "operator," and that it takes approximately 15 minutes to read and record the pressure, the annual cost of monitoring will vary with employment costs. If the total employment cost is $25/hour or $50/hour, the annual cost will be $325 or $650, respectively.

In practice, the measurement frequency of the annulus pressure will depend on the operating schedule, the stability of the measured pressure, the influence of temperature changes on pressure, and perhaps other factors.

4. Typical Requirements of Selected States

The rules and regulations of the states with regard to minimum standards in the performance of pressure tests and annulus monitoring are highly variable. While most states recognize the need to test an injection well for its mechanical integrity, they do not specify details of the test. A common approach used by many states is to require the well operator (permit applicant) to design and perform a pressure test and to submit the pressure tests data to the regulatory agency, who then reviews the data and renders a judgment on the integrity of the well.

Other states make a judgment of well integrity based on the casing and cementing program, as well as geologic and environmental criteria.

In contrast to pressure tests or annulus monitoring as required and specified for all classes of injection wells in Section 146.08, several states require tests that apply to specific types of injection wells. Oklahoma, for example, requires a pressure test on the casing of brine disposal wells at 300 psi or the authorized operating pressure, whichever is higher. On industrial disposal wells, where tubing and packer construction is required, the annulus pressure must be at least 20 psi, and monitored continuously. The tubing in these wells must be independently tested to withstand the higher of 150 percent of operating pressure or 300 psi. The state of Michigan also distinguishes the type of tests required for injection wells of different classes. Distinction in pressure test requirements is made in California between "onshore" and "offshore" injection wells, the offshore wells being more stringently controlled.

Because pressure tests can be performed on the casing, tubing, or on the well annulus, and at various pressures for various durations, and repeated with various frequencies, it is not surprising to find considerably different standards among the states. The states of Michigan and Oklahoma require pressure tests at pressures of 133 percent and 150 percent (or 300 psi, whichever is higher) of the operating pressure, respectively. The state of Florida requires pressure tests conducted at 150 psi with no pressure loss on certain Class I wells. On offshore wells, the state of California requires pressure tests at specific minimum pressures for each casing string emplaced. These pressures depend upon the bottom depth of the casing. Most states that require pressure tests do not specify the testing procedure.

The duration of pressure tests and minimum performance criteria also are rarely specified by state regulatory agencies. The pressure during tests as required on offshore wells in California for example, is not allowed to decrease by more than 10 percent in 30 minutes. The duration of a pressure test is one factor that regulators tend to leave to the discretion of the injection well operator.

Pressure tests are required once and only once by the majority of the states. Of those states that require more than one pressure test in the useable life of a well, California requires a test of onshore wells every six months, and Michigan requests tests biennially on brine production (injection) wells. Again, there is no consensus of regulatory opinion.

Requirements for monitoring the annulus pressure do not vary as widely as pressure test requirements. Monitoring of the annulus by manual measurement in Class I wells is required with a weekly frequency in Louisiana, while in Oklahoma and Texas continuous monitoring of the annulus pressure is required. Continuous monitoring is optional to pressure tests in several states. Such continuous monitoring involves the use of a recording pressure-measuring device, similar in concept to a recording barometer.

The pressure to be imposed on the well annulus during monitoring is generally not specified in state regulations. One exception is Oklahoma, which requires that a minimum of 10 psi be constantly maintained on the well annulus.

In summary, no consensus of philosophy or minimum requirements with regard to pressure testing exists among the states. Types of injection wells and/or problems with injection wells that are peculiar to a particular state have largely determined the rules and regulations a state has implemented.

III. GEOPHYSICAL LOGS REQUIRED IN THE UIC REGULATIONS

From among many of geophysical logs available from the major service companies, two are especially valuable in the detection and location of leaks and behind-the-casing fluid movement in injection wells. These are the noise log and the temperature log. Because of their unique abilities, one or the other of these logs is required in the test for mechanical integrity as specified in Section 146.08. The cost of these logs depends on the distance travelled by the service company, the type of log, time on site due to delays, and the pricing schedule of a particular company; thus, considerable variation in cost per logging survey will result.

The geophysical logs described in this section and in section IV are applicable to the majority of injection wells. However, wells will inevitably be encountered that contain obstacles, snags, or other potential hazards to the logging sonde. In order to protect the survey sondes, it is general practice to check the well clearance with a non-active and inexpensive "dummy." Also referred to as a sinker bar, this is a simple, smooth-surfaced, weighted bar having the approximate dimensions of the survey sonde that is to follow. Successful lowering and retrieval of the dummy in the well adds assurance that the desired survey(s) can be successfully performed.

Another pre-survey inspection of the well condition is the televiewer, which yields a visual record of the well bore. The use of the televiewer is usually reserved for a problems that cannot be identified by other than visual means. Application of the televiewer is limited to casing sizes 4 inches and greater.

In wells that cannot be logged because of configuration or size constraints, there remains no option to testing the well by pressurization. Testing for behind-the-casing fluid movement is thus precluded.

1. Noise Logs

The noise log was developed to detect and locate noise due to moving gases and fluids and is therefore well suited for mechanical integrity testing.

a. Basic Principles and Presentation

A noise logging tool detects sound energy created by the turbulent flow of fluids moving through channels, leaks, or any fluid constriction. Sound energy from a noise source is detected through cement, casing, gas, and borehole fluids. Sound is detected between the frequencies of 200 and 6,000 Hz and converted to an electrical signal. The logging tool or sonde is basically a sophisticated microphone. The resultant electrical signal is transmitted via cable to surface electronic equipment where it is recorded.

The noise signal has a wave form composed of a number of frequencies. Signal intensity indicates the presence (or absence) of fluid movement, leaks, etc. The noise log is a record of the amplitude of the signal, expressed in AC millivolts. Because noises associated with movement of the tool and wire-line in the borehole will mask out noise produced by leaks, movement, etc., a noise log is usually made with the tool in a stationary position and the survey is taken on a station-by-station basis. This survey technique is unlike other logs which provide a continuous record of the measured parameter with respect to depth. Recently, noise logging tools have become available which can make a continuous record by eliminating the noise signal generated by tool movement.

In addition to analysis of the amplitude of the noise signal, a frequency analysis can be made to determine the rate of flow through the channel and whether the detected flow is liquid, gas, or a combination. Such an analysis, however, is generally not essential for mechanical-integrity testing.

b. Application

The noise log can be used in fluid- or gas-filled casing. Tool diameters as small as 1.5 inches allow application in tubing having diameters of 2 inches and greater.

Application of the noise log is basically the same for any of the three classes of injection wells discussed herein. The construction of a well, and whether or not a well is fitted with a tubing and packer make little difference. The only effect the construction of a well may have on a noise log would be on the amplitude or strength of the noise signal. Because the signal is interpreted relative to background noise levels, it is not of major concern if it is somewhat attenuated, as long as it is clearly discernible from the background. Signal attenuation will occur in a well where the log is taken inside the tubing or in a large-diameter well when attempting detection of a behind-the-casing leak.

The noise log is applicable in both steel and PVC casings. In steel casing, sound energy is transmitted along the casing length more readily than in PVC. PVC casing, on the other hand, absorbs the sound more than steel. Given a noise of equal intensity behind a steel or PVC casing, the noise would be more intense, and present over a longer casing length with steel casing. The less intense noise arriving through the PVC casing, however, would nevertheless be detectable.

Significant noise can be detected in a steel casing at a distance of up to 200 feet above or below the source. In practice, it is customary to make station stops at depth intervals of 25 to 50 feet until a noise source is detected. In order to pinpoint the location of a noise source, a station-stop interval of 1 or 2 feet is appropriate. Unless a noise source is detected, noise logging can be nearly as rapid as continuous types of logging. Because each station stop requires about 3 minutes, however, stops that are 1 to 2 feet apart will obviously consume considerable time.

c. Interpretation

For mechanical integrity testing, it is sufficient to consider the noise log in its simplest form—a trace of noise intensity vs depth in the well. Interpretation in a steel or PVC casing is basically the same except for the signal attentuation in the PVC well. The amplitude of the noise log signal without further analysis of the noise spectrum cannot distinguish the direction of fluid flow, the rate of flow, nor can it indicate whether liquid or gas creates the noise.

A typical noise log is illustrated in Figure 6. In this example, fluid enters a channel behind the casing at a point opposite a permeable bed, moves upward, and departs the channel as it enters another permeable bed. Several important facts are revealed in this example. First, noise levels are greater than the background level over the entire length of the channeled section where fluid is moving. Second, the top and bottom peaks indicate the points of fluid entry and departure. The flow direction could have been shown downward on the diagram and the log would have looked essentially the same. Third, the middle noise peak on the log, the result of a constriction in the cement channel, could have been shown as another point of entry or departure and the noise log would have remained the same.

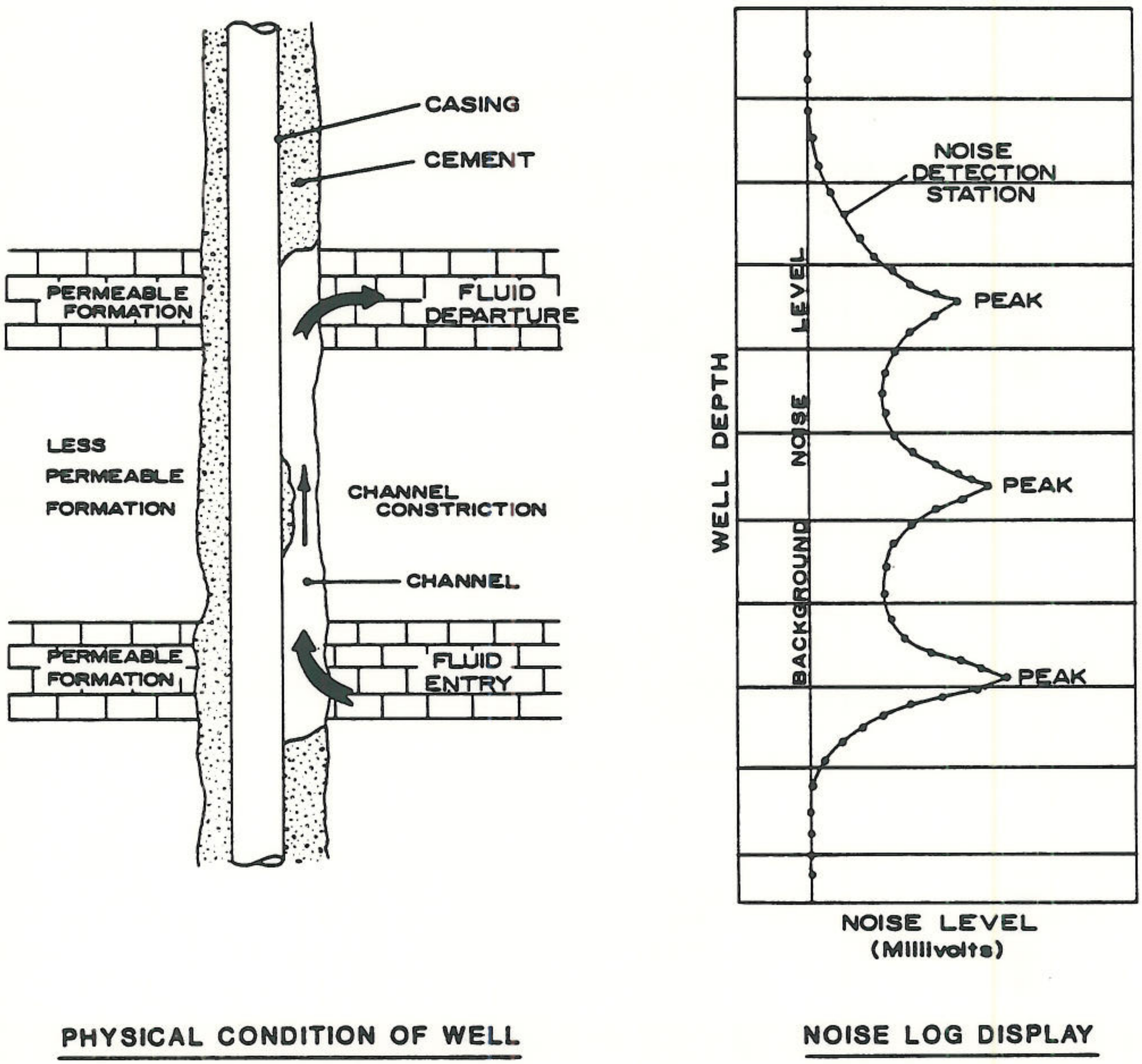


Figure 6

EXEMPLARY NOISE LOG DISPLAY

In combination with other logs, the capability of the noise log is enhanced. For example, the temperature log may indicate the direction of flow through the well bore after fluid movement is first detected by the noise log. The direction of fluid movement, however, may not be indicated by either log independently. The use of more than one geophysical log is a very common technique that should be used whenever economically possible to confirm a diagnosis.

2. Temperature Logs

Temperature logs are among the oldest of all geophysical surveys and are in widespread use. Along with the noise log, the temperature log is one of the optional tests used to confirm the absence of fluid movement in vertical channels in the well bore. It also has high utility in locating leaks through casing or tubing.

a. Basic Principles and Presentation

The temperature log is basically a record of the temperature and its variation with depth in a well. A temperature sensor is lowered into a fluid-filled well on a wire line. The device that measures temperature is a thermistor, which emits an electrical signal that is proportional to its temperature. This signal is relayed to the surface where it is represented on a strip chart that moves in the directon of increasing depth below the surface. The temperature log has an accuracy of at least 0.5 degrees F, and may be as great as 0.01 degrees F. The operating range is generally from 0 F to 350 F.

It has become common to run a differential temperature log simultaneously with the temperature log. This log is a record of the difference in temperature between two thermistors separated at a measured distance on the sensor probe. In essence, it serves to highlight those zones in the well where the temperature is changing rapidly as indicated by the temperature gradient. Both the temperature and the differential temperature are recorded and presented in the same fashion, and most commonly side by side on the same chart.

Temperature variations detected in wells are both natural and artificial. The manner in which the temperature departs from natural background temperature yields a diagnosis of well conditions including fluid movement behind the casing. The temperature of the earth increases with depth below the surface at a rate of approximately 1 degree F per 100 feet (the geothermal gradient). There are many exceptions to this generality, especially in the upper hundred feet or so where ground water circulates and temperatures may be influenced by seasonal variations. The temperature at a depth of about 100 feet is generally about 3 degrees F greater than the mean annual air temperature at any location. Below this, the temperature rises in approximately linear fashion with depth. Variations in temperature due to natural causes are usually quite gentle and follow smooth trends. In contrast to natural trends, temperature changes due to well characteristics are likely to be abrupt, and therefore distinguishable.

b. Application

Temperature logs may be run on fluid-filled casings as small as two-inches in diameter, and are feasible in any class of injection well. Wells of a particular design in any class, however, may present similar problems to the application of the temperature log. A well fitted with tubing and packer, for example, requires the removal of the tubing in order to properly detect or locate fluid movement behind the casing. This is because temperature anomalies may not be transmitted through the annulus and tubing. Temperature logs are applicable in both steel and PVC casings. Because of the lesser heat conductivity of PVC, however, thermal anomalies transmitted through the casing would be somewhat diminished.

For the purpose of detecting and locating fluid movement behind the casing, temperature logs should be taken under conditions of thermal stability. A temperature log of a flowing well will reflect the temperature of the flowing fluid in the entire cased interval, making detection of a relatively minor temperature difference impossible. In such a well the probe and wireline would have to be placed in the well and the log run through a device known as a stripper head or lubricator in order to stop any flow and prevent spills.

Another well condition that must be avoided is that of a recently cemented well, where temperatures will reflect the heat of hydration of the cement. This heat is sufficient to mask the minor differences sought in the temperature log test. Many days may be necessary for the heat of hydration to dissipate in the vicinity of a well. The time required will, of course, vary with well dimensions. If the temperature of a well is measured before cementing, it then becomes a simple matter to wait for the well temperature to return to near this point after cementing, in order to run an acceptable temperature log.

The diameter of the well is yet another factor that can control the efficacy of the temperature log. The degree of correlation between the temperature log and the temperature at or behind the casing is reduced in a large-diameter well (greater than 12-inch-diameter) due to the thermal attenuation that occurs between the source of the anomaly and the logging probe. The temperature log of a large-diameter hole also may reflect an inverted temperature relationship wherein the warmer fluid near the bottom of the well has migrated towards the top due to its relatively greater bouyancy.

c. Interpretation

Fluid leaks and movement in channels behind the casing will display characteristic signatures on temperature logs. Typical temperature logs are shown in Figure 7-A, B, and C. Example A shows an idealized geothermal gradient that typifies a temperature log in a stable well without behind-the-casing fluid movement. Example B shows, superimposed on the geothermal gradient, an anomaly in temperature due to the downward movement of fluid. The channel conducts the relatively cooler fluid to lower level thus causing a low-temperature bulge in the normal gradient. Example C shows the opposite effect where the upward movement of fluid causes a high-temperature bulge in the normal gradient.

Departure of a temperature log from the geothermal gradient may be due to many reasons other than leaks or fluid movement behind the casing. As alluded to above, the geothermal gradient is a general concept; in reality, the gradient may deviate as a function of various subtle factors. Several of these factors that are most likely to be encountered include the heat associated with volcanic rocks (intrusives), variations in heat conductivity of geologic formations, and the flow of ground water. In order to understand how these influences to the average gradient may be manifest in a well, substantial information on the geology of the subject area is essential. For example, is the area known to be influenced by geologically-recent volcanic activity? Are there significant differences between the heat conductivity of adjacent geologic strata? Do significant aquifers exist in the borehole interval? What is the ground-water flow path, and does ground water gain or lose heat to identifiable geologic features? Do ground-water convection cells exist in the aquifer? The answers to these questions may provide the key to temperature log interpretation.

Within the context of the above, interpretation of a temperature log as a mechanical integrity test must address the relative size and vertical height of a thermal anomaly. If the accuracy of the log is 0.1 degrees F, the average geothermal gradient would have to be disturbed in an interval of at least 10 feet in the vertical direction in order for a thermal anomaly to appear. A minimumally detectable anomaly would thus indicate behind-the-casing flow through an interval of 10 feet or greater. Anomalies caused by fluid movement from one to another are likely to be considerably greater in vertical height. Close to the land surface (<100 ft), seasonal effects and rapid ground-water circulation may significantly alter the geothermal gradient making it unsuitable as

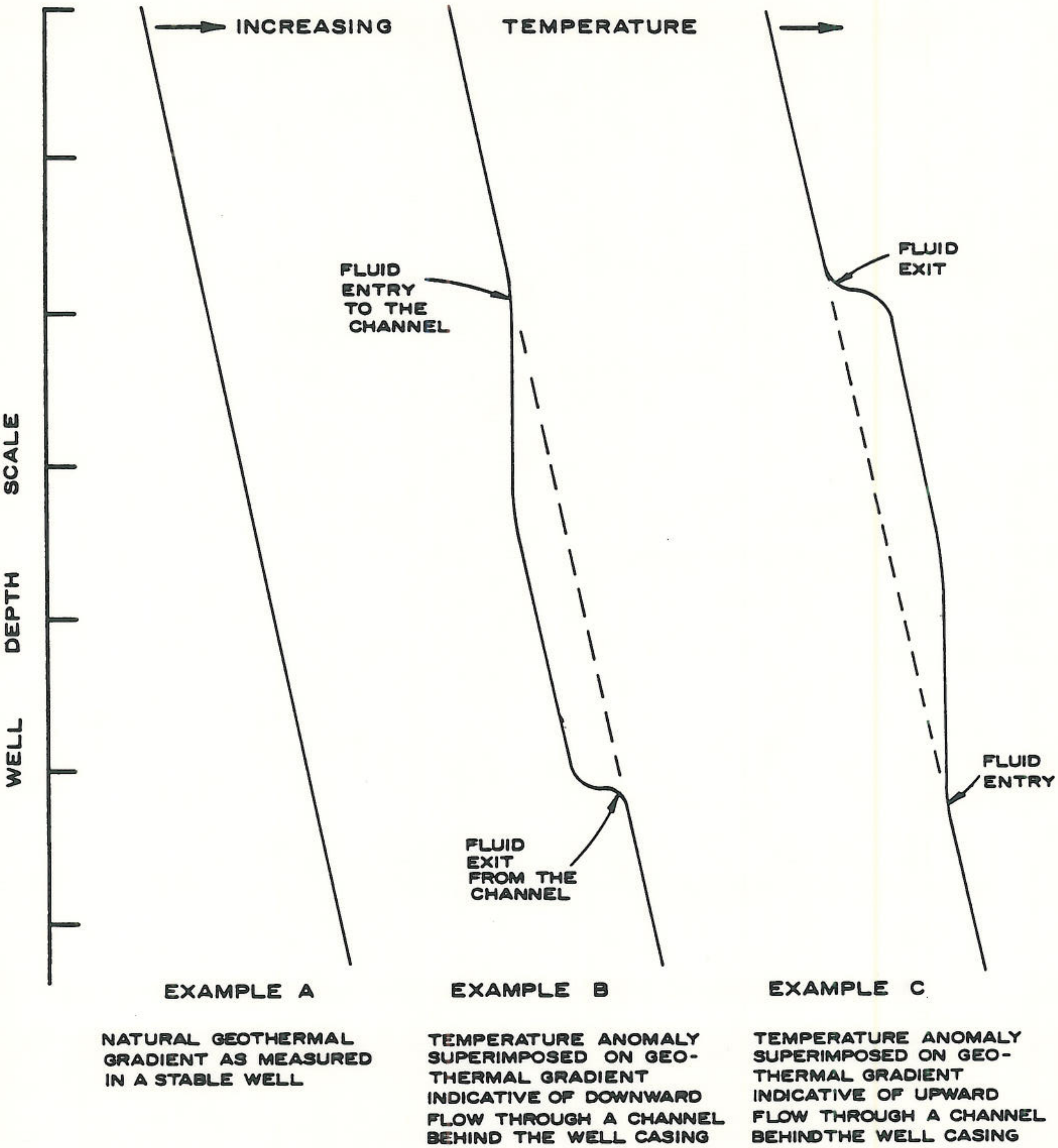


Figure 7

EXAMPLES OF TEMPERATURE LOGS SHOWING THE NATURAL GEOTHERMAL GRADIENT AND ANOMALIES CAUSED BY FLOW THROUGH A CHANNEL BEHIND THE WELL CASING a standard background for the detection of a thermal anomaly. For this reason and others, the average geothermal gradient should not be considered the only acceptable standard background for the detecton of a thermal anomaly. In reality, any deviation in temperature from an otherwise smooth trend in temperature should be suspect as indicative of undesirable fluid movement or a leak. If available, temperature logs run before well completion can be used to establish a background reference. As in the case of the noise log, temperature logs should be interpreted with the aid of other geophysical logs to eliminate ambiguities.

IV. ADDITIONAL GEOPHYSICAL LOGS THAT MAY BE USED FOR DETERMINING MECHANICAL INTEGRITY

Aside from the noise log and temperature log, many other geophysical logs have the ability to indirectly indicate problems with the casing and cement grout of an injection well. These logs may be used as supplementary to the required log or as alternatives. For use as alternatives, they require the written approval of the EPA Administrator (such approval will be published in the Federal Register and may be used in all states unless restricted by the Administrator). Several or all of these logs may be run while the logging service company is on-site for the required log.

1. Radioactive Tracer Logs

Radioactive tracer logs can be used to determine the travel path of fluids wherever a small quantity of radioactive material can be injected into the flow stream. The potential of the radioactive tracer log for confirming the mechanical integrity of an injection well lies in its ability to trace the movement of fluid behind the casing.

a. Basic Principles and Presentation

The radioactive tracer survey consists of making a comparison of two gamma ray logs, one run before and one after the injection of a small quantity of radioactive tracer material. Following the first gamma ray log that establishes the background reference, the injection is made in the well in the vicinity of where a leak or fluid movement is suspected to exist, so that the tracer material is taken into the flow stream at the leak. The second gamma ray log is then taken and the path followed by the tracer through the leak is described by higher than background gamma radiation on the log. The superposition of the before and after gamma ray logs is the radioactive tracer log.

The probe or sonde used in making the radioactive tracer log consists of a tracer ejector and one or more gamma ray detectors. There is usually substantial flexibility in the physical arrangement of these components in the probe assembly. A radioactive tracer material having a very short half life is injected into the well, tubing, or casing, in small quantities of about 0.1 ml each. Even with this small amount of tracer fluid, there is usually a substantial contrast in gamma radiation intensity between the natural background source and the injected tracer source. The tracer most commonly used is Iodine 131 which has a half life of 8.04 days.

The method of tracer log presentation is the straight-forward superposition of gamma ray logs with the radiation intensity expressed in cycles per second or API units. The two log traces are usually distinguished on the chart by the type of line used (solid, dashed, or dotted).

b. Application

The radioactive tracer log has application in all injection-well classes, in all casing materials and designs, in casings having diameters of 2 inches and greater. The method of application, however, differs according to the nature of the suspected leak and the well design.

In the case of injection wells with no tubing, the radioactive tracer log can be used to trace the movement of fluid through a leak at any point in the casing, or beneath the bottom of the casing and into channels in the cement of the well bore. Following the first, or background gamma ray log, a dose of tracer material is ejected near the suspected leak. After an appropriate period for the tracer to enter the leak, the casing should be flushed and another gamma ray log run to detect the remnant tracer material behind the casing. Additional gamma ray logs can be run periodically to observe the movement of the tracer with time.

A similar procedure can be used to detect leaks in the tubing of an injection well. In the case where fluid movement exists in a channel behind a leakless casing, however, there is no way to eject the tracer material into the stream of fluid to trace its movement. In this case, the radioactive tracer log is not applicable except for testing the adequacy of the cement at and immediately above the casing shoe.

The operating limits of the radioactive tracer log are defined by the detectability of the tracer material. The detectability is a function of the radioactive strength and the amount of tracer, the flow rate through a leak and the contrast between the injected radiation and the natural background radiation. Except for the tracer dosage, these factors cannot be controlled.

c. Interpretation

The interpretation of the radioactive tracer log involves the comparison of gamma ray logs taken before and after the introduction of tracer material (Figure 8). If the well is flushed after the injection of the tracer, then an increased gamma radiation shown in the second log would indicate the point of a leak. Well flushing would not be necessary if enough time were allowed after the injection of the tracer and before the second gamma log, so that all the tracer could have migrated through the leak. An anomaly that persists in an unflushed well and the absence of an anomaly in a flushed well indicate the absence of a leak.

An anomaly may exist at a single point (depth) and indicate horizontal migration of the tracer away from the well, or an anomaly may spread over a range in depth and indicate vertical movement of the tracer and the presence of a channel behind the casing. The interpretation of a radioactive tracer log, like other logs, should be tempered with clues from all possible sources, especially other geophysical logs.

2. Cement Bond Logs

The cement bond log was developed specifically to determine the condition of cement behind the casings. It is applicable in wells having diameters of 2 inches and greater. By itself, it does not indicate whether fluid movement occurs, but it does indicate if the potential for fluid movement exists (i.e. the absence of cement or the presence of channeled cement). Another survey that also determines the condition of the cement behind the casing is commonly run simultaneously to the cement bond log. This complementary survey is called the 3D Velocity Log by the Birdwell Division, the Acoustic Signature Log by Dresser Atlas, the Variable Density Log (VDL) by Schlumberger Well Services, and the Microseismogram by Welex. The following describes both the cement bond log and the VDL (choice of this name implies no preference).

a. Basic Principles and Presentation

The principles of the cement bond log and VDL logs offered by the various companies are essentially the same. The logging sonde is equipped with a transmitter and two receivers. The receivers are set at different spacings; one is utilized for the cement bond log, and the other for the VDL. The transmitter emits a signal with a ringing frequency of 20 to 25 kHz (kilohertz) that is radiated in all directions. The tool is centralized within the bore hole and run on a wire line; a continuous record is made.

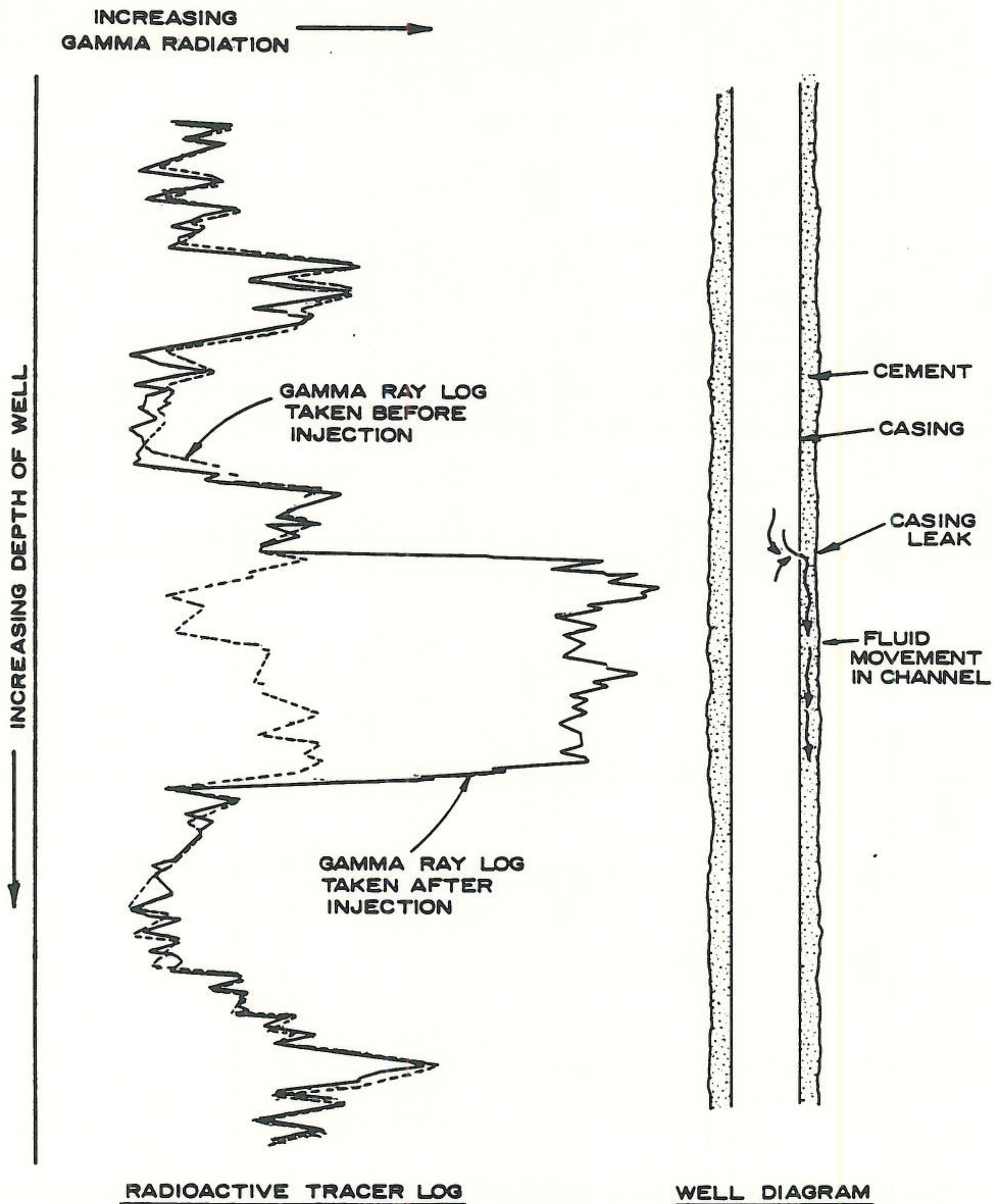


Figure 8

RADIOACTIVE TRACER LOG SHOWING
THE DETECTION OF A LEAK IN THE CASING
AND SUBSEQUENT FLUID MOVEMENT
IN A CHANNEL BEHIND THE CASING

The cement bond log receiver, which is usually set three feet from the transmitter, detects and measures the amplitude of the first arrival of the sound energy. In effect, this logging method depends on the difference between the energy loss of a sound pulse traveling through casing that is standing free (no bond) in the hole, and the energy loss of a pulse travelling through casing that is firmly bonded to a hard material of a low sonic velocity, such as cement. The sound pulse will travel through free casing with very little attentuation, whereas the sonic pulse loses energy continuously to the cement sheath and a large signal attentuation results when the cement is firmly bonded to the casing.

By recording the amplitude of the first arrival, it is possible to locate points in the cemented section where the bond may not be adequate and a potential for fluid movement exists. Laboratory experiments have shown that the signal attentuation in cemented pipe is proportional to the percentage of the casing circumference that is bonded with cement, and that a decrease in attentuation to less than 70 to 80 percent of the maximum value may indicate cementing problems.

The VDL log, when used in conjunction with the cement bond log, can provide additional information on the quality of the cement. The VDL receiver on the sonde is usually set 5 feet from the transmitter. Basically, the VDL log is a photographic display of the arrival of the sonic signal as produced on a special oscilloscope. The photographic record of a VDL log appears as a series of alternating light and dark bands representing variations in positive and negative signals. A continuous record of the wave train is made as the logging tool is raised or lowered in the bore hole.

A typical presentation of a cement bond log and a VDL is shown on Figure 9. These logs were taken in a bore hole in which known portions were cemented and uncemented (the uncemented portion was gravel packed). The uncemented part is shown by a high amplitude signal on the cement bond log display (no signal loss to the formation), whereas the cemented portion of the casing is indicated by the low amplitude of the signal.

The VDL display indicates both the condition of the casing-cement bond and the formation acoustical coupling. The earliest arrivals shown on the VDL display indicate the condition of the casing-cement bond and lend verification to the cement bond log. Later arrivals indicate the condition of the acoustical coupling of the cement and the formation. If the cement is well-coupled to both the casing and the formation, the later arrivals on the VDL are indicative of the formation characteristics as the sound energy penetrates deeply.

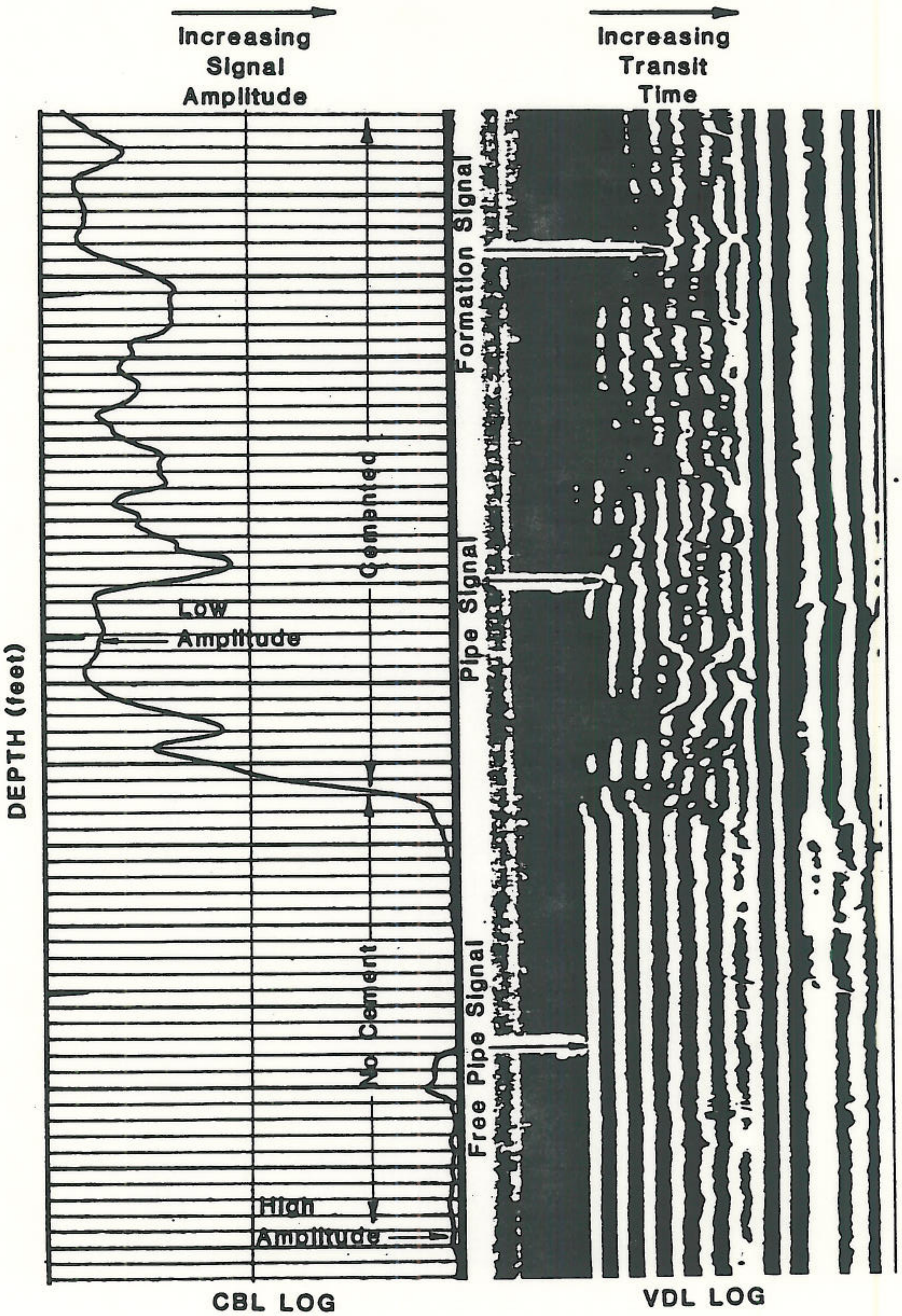


Figure 9

TYPICAL CEMENT BOND LOG AND VDL DISPLAYS

The VDL display (Figure 9) shows a characteristic, strong, "free pipe" signal which gives the appearance of the undistorted alternating light and dark bands. In this zone, no signal strength is lost to the formation, accounting for the rather sharply defined VDL display.

In summary, the cemented portion of the casing is characterized by the low amplitude signal on the cement bond log, the weak almost indistinguishable pipe signal on the VDL, and the wavy, and irregular formation signal on the VDL.

b. Application

The cement bond log and VDL have application in determining mechanical integrity in any injection well that has a cemented casing. Wells with tubing, however, can only be surveyed after the removal of the tubing. In PVC casings, results of the cement bond log are somewhat compromised because of signal attenuation. This can be at least partially overcome by comparing the log response of a cemented interval with an interval known to be free of cement. Anomalous signals that appear in the cemented interval and show similar characteristics as the uncemented interval, indicate suspected locations of poor bonding. This testing technique, to the extent possible, should be implemented on all casing types. The condition and extent of cement bonding behind the casing are strong indicators of the mechanical integrity of a well. However, these logs only indicate the presence or absence of an adequate bond, and do not detect fluid movement.

c. Interpretation

The interpretation of the cement bond log and VDL is described above. This description is sufficient in the majority of cases where well integrity is being tested. There are, however, several aditional interpretive problems (such as distinguishing a micorannulus from channeling), that require a more detailed knowledge of these logs and probably further tests. These problems are unusual and not considered essential to understanding the basic use of these logs.

3. <u>Caliper Logs</u>

The Caliper Log is a straight-forward record of the borehole or casing diameter as it varies with depth. The application of the caliper log as a tool to determine the mechanical integrity of a well is made only for the detection of the most exaggerated distortion in the diameter of a casing. Although the caliper log cannot detect leaks or fluid movement behind the casing, these problems may occur sometimes in association with a distorted casing.

a. Basic Principles and Presentation

The production of a caliper log entails the lowering of the caliper probe to the bottom of the borehole, releasing the detector arms, and raising the probe in the borehole to produce a record of the variation of borehole diameter with depth. The probe consists of a central shaft fitted with three or more hinged arms that fold against springs into the side of the shaft when fully retracted. As the probe is pulled upward in the borehole the detector arms extend where the borehole has a large diameter and retract at locations having a small diameter. The movements of the arms are converted to an electrical signal that is transmitted to the surface and recorded on a plot showing the average borehole diameter versus the depth. The borehole or casing diameter is usually calibrated and recorded in units of inches.

Caliper probes having four or six detector arms are available that enable the determination of the shape of the borehole cross-section. This is useful in mechanical integrity testing, as the shape of a distorted casing cross-section has a significant bearing on the determination of the degree and possible cause of casing damage.

b. Application

The caliper log, like other logs, is not limited or less applicable to any one injection well class. It is equally applicable in steel and PVC casings. Well construction, however, does make a difference. Tubing wells must have the tubing removed before the casing can be logged.

The operating range of a caliper tool is commonly from 4 to 24 inches, with an accuracy over this range of 1/4 inch. Wells being tested for mechanical integrity would seldom have dimensions outside these limits. Tools capable of measuring diameters up to 60 inches are available.

c. Interpretation

The caliper log is interpreted in a straight-forward manner. The average well diameter measured at any depth is the diameter displayed on the strip chart. A six-arm caliper log will be represented by four traces on the log. One trace represents the average diameter of the casing borehole. The remaining three traces indicate the diameter of each of three pairs of arms. Thus, differences in diameter and cross-sectional borehole shape can be determined.

4. Casing Condition Logs - The Thickness Log

Recognizing that corrosion and its effect on the mechanical integrity of a well is an important factor in the economic production of hydrocarbons, geophysical logging companies have developed logs to determine the condition of well casings. Two distinct principles of detection are employed in these logs. For convenience sake they will be referred to as the thickness log and the pipe analysis log, although the names vary with each logging company. These logs are applicable to wells having steel casings and tubings and are indirectly indicative of the mechanical integrity.

a. Basic Principles and Presentation

The thickness log, also referred to as a magnelog, employes a sonde on a multi-conductor wireline and surface electronic circuitry to detect and amplify the signal and reproduce it in conventional log form. The casing thickness is evaluated by measuring the phase shift of a low-frequency alternating current signal emitted by a transmitter coil and detected by a receiver coil spaced at a fixed distance from the transmitter in the sonde.

The transmitter coil sets up a magnetic field inside of the casing, in the casing itself, and outside of the casing. The receiver coil is spaced so that it intercepts only the lines of magnetic flux that pass outside of the casing. Because the lines of flux must pass through the casing at two places, the phase of the induced current in the receiver coil leads that of the transmitter. The flux lines pass through the casing more or less perpendicular to the casing wall. Consequently, pipe thickness affects the phase shift, with the maximum phase shift (for a given section of pipe) being where the wall thickness is the greatest. The log, therefore, takes advantage of this relationship to give an indication of the condition of the casing by using changes in the phase shift to measure thickness variations.

b. Application

The thickness log will function in fluid-filled steel casings from 4-1/2 to 8-5/8 inches in diameter. It is applicable only in metallic casings. Because a relatively large area is investigated, the tool has a limited resolution and the smallest casing defect (hole) it can detect is about one inch in diameter. The thickness log cannot distinguish between inner-wall and outer-wall defects;

however, when used in conjunction with the pipe analysis log, it can be used to distinguish which of two concentric casings is defective.

c. Interpretation

Casing is manufactured in a variety of dimensions, weights, and alloys. Each will respond to the thickness log in a different manner because of variations in the magnetic and electrical characteristics of the casings. Because of these differences, proper interpretation of the log requires a knowledge of the diameter, weight, and type of steel casing being logged. Similarly, the locations of couplings, wall scratchers, perforations, centralizers, etc., should be known because they too, will influence the log. An example of this is shown on Figure 10, which is a "thickness" log for different weights (wall thickness) of 5-1/2-inch-diameter casing. The sharp peaks to the right at regular intervals are due to the couplings. An area interpreted as corrosion is shown at 1024 feet, where there is a reduction in thickness from the "normal" for the pipe.

5. <u>Casing Condition Logs - Pipe Analysis Log</u>

This logging survey, based on measurements of flux density variation and eddy currents, is used to provide a more quantitative assessment of casing condition than the thickness log. This tool also can discriminate between defects on the inner and outer casing walls.

a. Basic Principles and Presentation

The log is a form of magnetic flux-leakage test, relying on disturbances in an artificially-created magnetic field to detect casing defects. The probe houses from six to twelve coils (depending on the size of casing being surveyed), through which a DC current is passed, setting up a magnetic field. The field consists of magnetic flux lines that travel through casing easier than through gas or fluids.

The logging probe employs a magnetic field strong enough to saturate the casing walls with magnetic flux lines. As long as the wall of the casing is uniform and consistent, the magnetic flux lines will travel through it. When irregularities such as pits, holes, partings, cracks, etc., are present, the flux lines will be disturbed and flux leakage will occur. In an area where flux leakage occurs, a small voltage is generated and detected by transducers which relay a signal that is proportional to the percentage of metal loss in the casing. This signal is recorded in chart form.

Descrimination between internal and external corrosion of the casing is accomplished by monitoring the variations in eddy currents

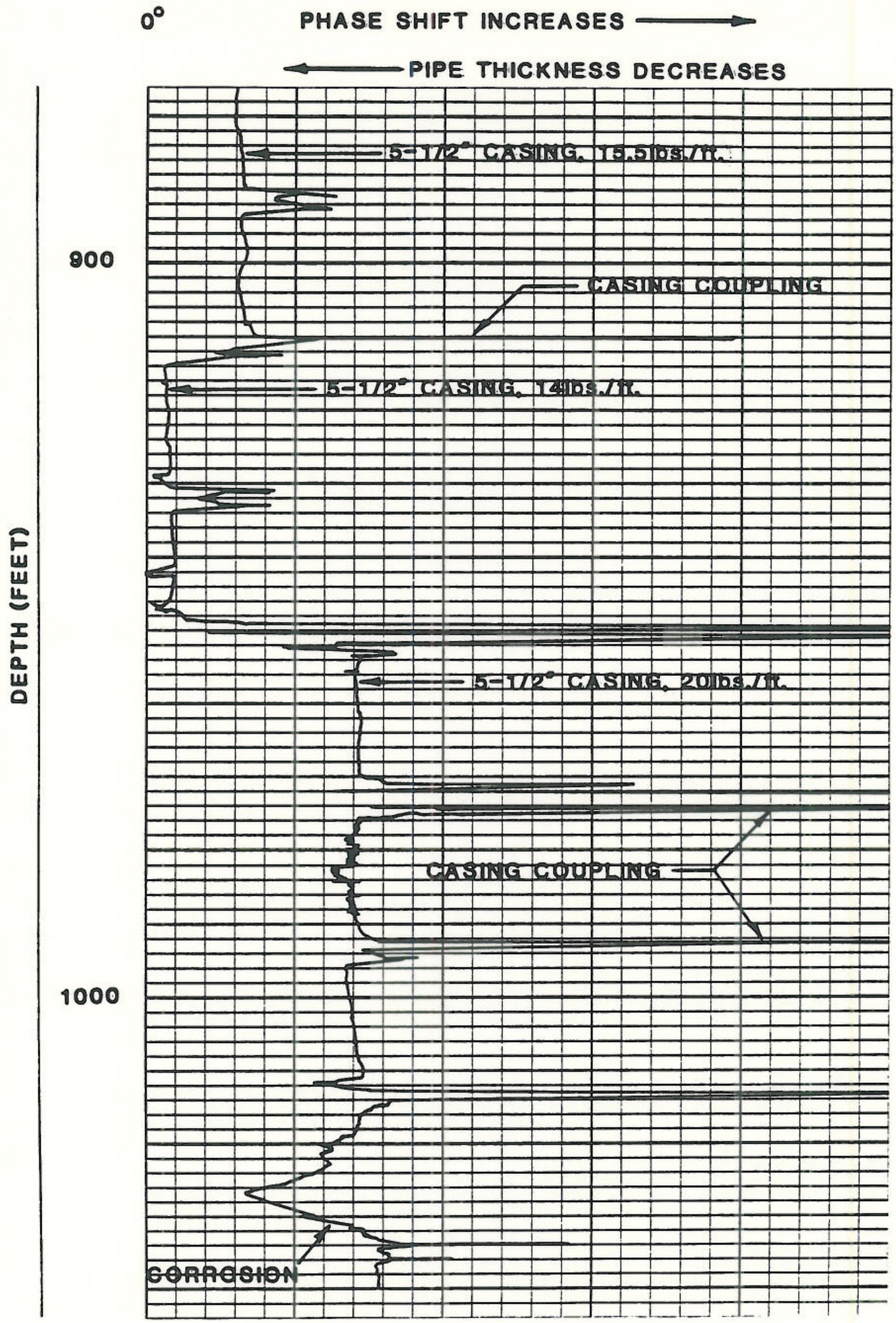


Figure 10

TYPICAL THICKNESS LOG DISPLAY

generated in the magnetic field by pipe defects. The coils used to detect eddy currents are co-located with the flux-leakage transducers (coils). The signal frequency of the eddy currents detected is high, such that the depth of investiation is shallow, usually about 0.040 inch. Thus, the eddy current detector investigates only the inside of the casing. Comparison of the flux leakage with the eddy current signals makes it possible to distinguish between inner and outer casing wall defects. An inner casing wall defect will influence both flux leakage and eddy current signals, whereas an outer wall defect will influence only the flux leakage signal.

The logging probe is run in a centralized position in the casing. Coils are staggered on the probe so they overlap each other to provide circumferential coverage of the casing. The coil mountings are spring loaded that adjust to the size of casing to be inspected.

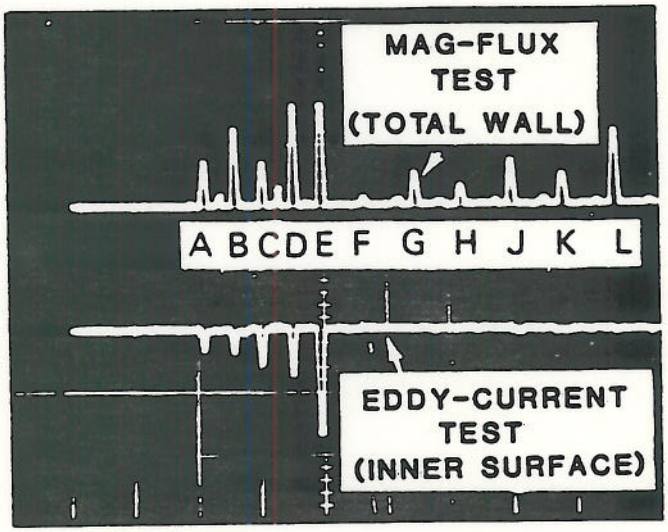
The flux leakage and eddy current signals are detected, amplified, and presented as a series of curves or tracers on standard log forms. As noted, the amplitude of the flux leakage signal on the log is proportional to the percentage of the metal loss in the casing. Thus, the greater the amplitude of the signal, the greater the casing defect. An example of this is shown on Figure 11 and its accompanying table, which is the record of the signals produced by known anomalies in a test piece of casing. Examination of the signal produced by internal defects A and B, which are 3/8-inch-diameter holes with wall penetrations of 25 and 50 percent, respectively, shows that the magnitude of the signal is proportional to the loss of casing (depth of penetration of the defect). The external defects producing signals K and L, which are 3/4 of an inch in diameter, appear on the total wall trace but not on the eddy current test, demonstrating the means by which internal and external wall defects are discriminated.

b. Application

The pipe analysis log is designed for use in steel or other metallic casings ranging from 4-1/2 to 8-5/8 inches in diamter. The tool can be run in a fluid- or gas-filled casing. The pipe analysis log responds to all changes in casing "thickness" and will be affected by couplings, DV collars, perforations, wall scratchers, centralizers, mill defects, and different pipe weights and grades of steel. Thus, the details of the normal casing condition should be known so that their presence can be recognized during interpretation.

c. Interpretation

A typical log display is shown on Figure 12, which is an example of the Pipe Analysis Log provided by Schlumberger Well Services. The



DEFECT	LOCATION	DIAM. (in.)	PERCENT WALL PENETRATION
A	INTERNAL	3/8	25
B	INTERNAL	3/8	50
C	INTERNAL	1/2	25
D	INTERNAL	1/2	50
E	INTERNAL	3/4	25
F	EXTERNAL	3/8	25
G	EXTERNAL	3/8	50
H	EXTERNAL	1/2	25
J	EXTERNAL	1/2	50
K	EXTERNAL	3/4	25
L	EXTERNAL	3/4	50

Figure 11

COMPARISON OF SIGNALS PRODUCED BY KNOWN PIPE DEFECTS

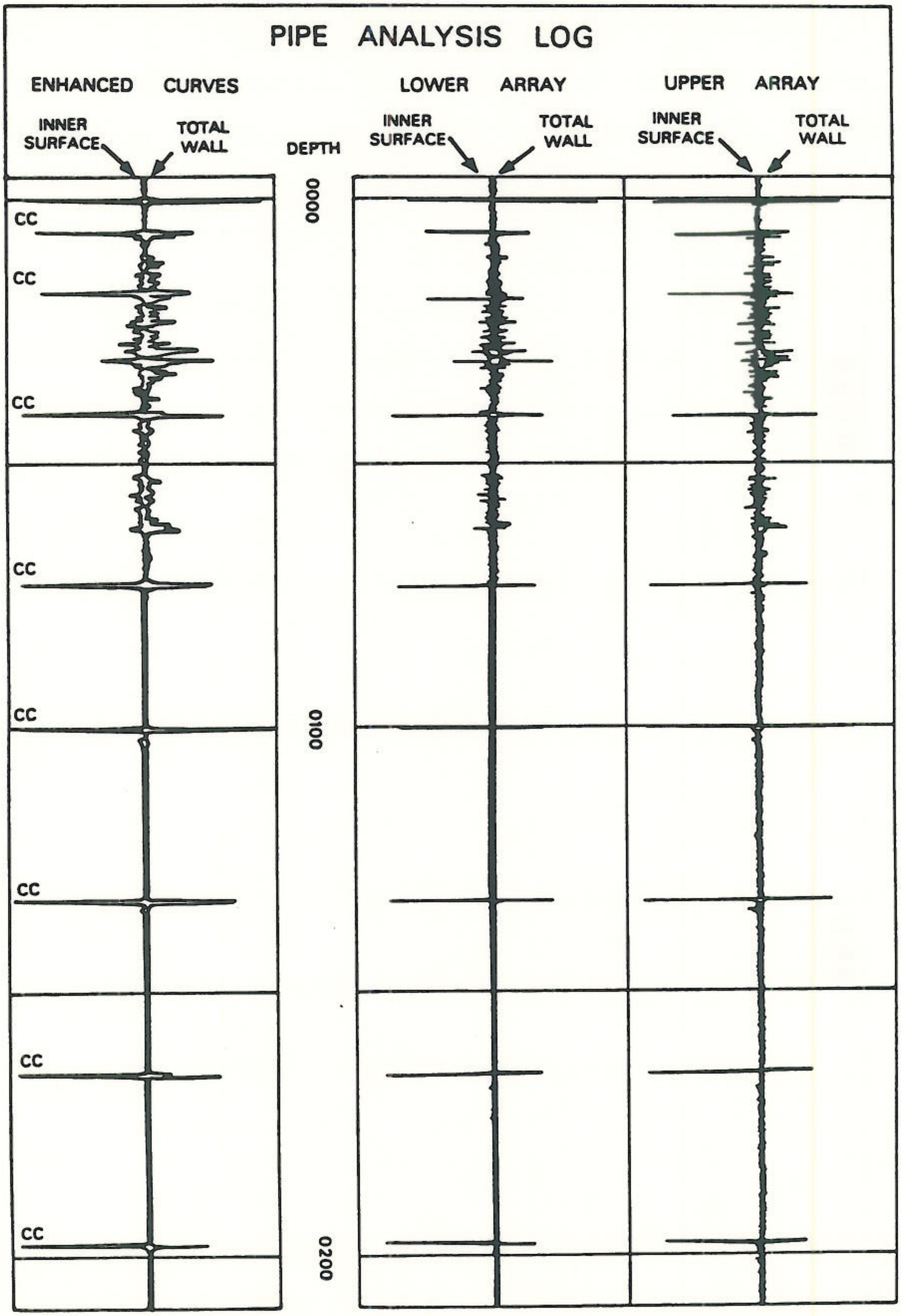


Figure 12
TYPICAL DISPLAY OF THE PIPE ANALYSIS LOG

The flux leakage signal is referred to as "Total Wall" and the eddy current signal is called the "Inner Surface." The enhanced curves on the left-hand track are derived from the maximum signal from any of the transducer coils and are used to emphasize major defects. The term "CC" refers to casing coupling. Obvious defects can be seen on the casing above a depth of 70 feet. Because they appear on both the inner surface and total wall curves, they are interpreted to be defects on the inner wall of the casing.

The Dresser Atlas log that measures the same parameters is known as the Vertilog. Its manner of presentation is slightly different (Figure 13). Two tracks known as FL1 and FL2 are presented; these measure flux leakage. One track is shown as the discriminator; it measures eddy currents and is used to determine inner wall defects. The fourth track is a display of the average signal and is used to determine if the defect is circumferential in nature and to confirm that the tool is working properly. Any time a signal is recorded on a flux leakage track, a corresponding signal should be recorded on the average track. A typical Vertilog should be recorded on the average track. Examination of the log on the right side of Figure 13 shows the log response for couplings and for various degrees of corrosion and distinguishes between internal and external corrosion. The left-hand log presents the results of the survey of a casing in reasonably good condition with a few defects. The terms Class 1, 2, etc., refer to a classification of the condition of the casing, based on the percentage of the deterioration; it is used by Dresser Atlas in its reports of casing condition surveys (Class 1 represents defects equal to 0 to 20 percent of the wall thickness, Class 2 from 20 to 40 percent, Class 3 from 40 to 6 percent, and Class 4 from 6 to 80 percent).

Survey data are compared to standard charts derived from laboratory-made defects on test casings to determine the percentage of deterioration. Typically, an oil-well operator is not concerned about casing condition until a Class 4 defect appears, whereas the operator of a gas storage well would be concerned when a defect reached 20 percent of the wall thickness.

Of the two casing condition logs, the pipe analysis tool is the most sensitive and is capable of detecting relatively small defects. Both, however, are valuable tools. One suggested method of using them is to run one at the time a well is constructed, to serve as a reference for future comparison. If the well is operated on a long-term basis, subsequent logs can be used to obtain some idea of the degree of deterioration and an approximation of its rate.

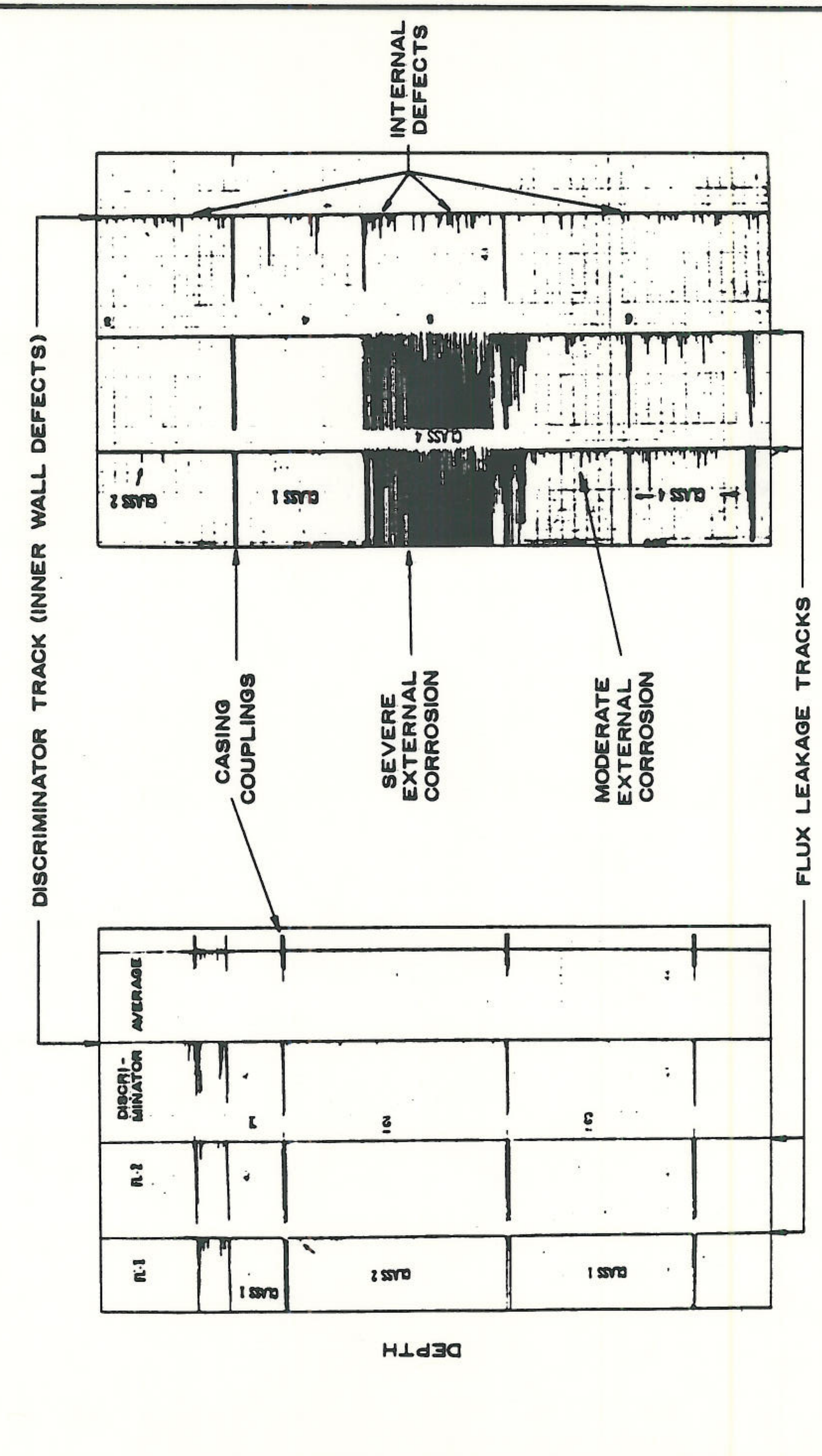


Figure 13
TYPICAL DISPLAY OF THE VERTILOG

V. WELL RECORD EVIDENCE OF MECHANICAL INTEGRITY FOR CLASS II INJECTION WELLS

The absence of fluid migration behind the casing of injection wells associated with the production of oil and gas (Class II) may be demonstrated by well records showing adequate cement to prevent such migration. This exception for Class II wells is made so as not to impede the production of oil and gas by the requirement of temperature or noise logs.

The main criteria for a determination of whether "adequate" cement exists is the comparison of the volume of cement injected and the volume of the space between the outer casing and well bore. The volume of cement injected should be included in well-completion records. The volume of the space between the casing and well bore, the annular space, is calculated on the basis of the outside diameter of the casing and a caliper log of the well bore. Records that indicate the level of cement fill-up are "tag" readings (where the top of the fill is detected by resistance to further lowering of a weighted line), cement bond logs or temperature logs.

If the volume of injected cement fills significantly more than the theoretical volume, then an adequate cement seal may be absent, and vertical channels are possible. Unfortunately, there is no sure way of knowing the adequacy of cement on a volume comparison basis. Experience, especially with regard to the geology in the well-bore environment, plays a key roll in well record interpretation.

If the injected cement volume is greater than the calculated annular volume it is assumed that the annular volume is underestimated due to limits imposed by the caliper log. Caliper logs may be unable to measure the full diameter of the borehole in an unusually ragged or cavernous zone; therefore a greater volume may exist between the casing and the well bore than that calculated. In this case, especially in the light of corroborative geologic evidence, an adequate cement is considered likely.

A cement bond log showing a tight casing-to-formation bond over the cemented interval is also considered adequate assurance of mechanical integrity.

VI. GENERAL CONSIDERATIONS

The testing for mechanical integrity entails the execution of a number of steps, each one a specific test, that together provide assurance that the tested well is environmentally sound. At least two tests are required though more may be necessary if the results of these are not conclusive.

The two required tests are a pressure test (or monitoring) and a geophysical log (either noise log or temperature log). Other tests may be substituted for these two, if approved by the EPA Administrator. If either of the tests indicate well failure, then other tests are necessary, first to veryify, and then to locate and understand the failure for effective remedial action.

Pressure tests and annulus monitoring are conducted at the well head and yield the most valuable indication of mechanical integrity. The results of these tests are quantitative and definite. Unless pressure testing is staged, the tests cannot be used to locate a failure. However, they can be used to isolate the failure to either the casing, tubing, or packer.

The results of the geophysical logs are more qualitative, because they are indirect methods of leak or channeling detection. They rely on the detectable variation in some physical parameter to provide an indication of failure, as expressed by an anomaly in the expected behavior of the parameter. The geophysical logs, provide the only means of locating a failure.

From the discussion above, the reader should have a basic understanding of how the required and potentially useful tests are performed, and what results can be expected from them. The selection of tests to be utilized in any particular case should be carefully considered, drawing on the available well construction data, and the expertise of the driller, operator, and logger.

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