United States
Environmental Protection
Agency

Technology Transfer

EPA/625/9-87/007

EPA

# Injection Well Mechanical Integrity

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EPA/625/9-87/007

# INJECTION WELL MECHANICAL INTEGRITY

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## ABSTRACT

Underground injection control regulations of the U.S. Environmental Protection Agency require that all injection wells demonstrate mechanical integrity, which is defined as no significant leak in the casing, tubing or packer; and no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore.

This initial research project, examining the question of mechanical injection well integrity, was conducted by the Robert S. Kerr Environmental Research Laboratory and funded in 1981. The three-phased project determined the state-of-the-art methods available for mechanical integrity testing of injection wells and field tested specific analysis methods to determine their adequacy as mechanical integrity tests.

The first phase of the project resulted in a separate report entitled, "Methods for Determining the Mechanical Integrity of Class II Injection Wells." The report represented state-of-the-art methods available for determining mechanical integrity of Class II wells. The technology described, may also be applied to other classes of injection wells.

The second and third phases of study involved two test wells, constructed for mechanical integrity testing: A "Logging Well" to test for channels in the cement behind the casing and a "Leak Test Well" for developing methods for testing the integrity of the tubing, casing and packer as well as locating fluid movement in channels behind the casing.

Channels covering 90, 60, 30, and 6 degrees of the 360 degree circle described by the casing were built into the cement of the "Logging Well." Two generations of logging tools were run in the Logging Well: the "cement bond" tool and the "cement evaluation" tool.

None of the logging tools presently available located any of the 6 degree channels. The "second generation" tools located all of the 30, 60, and 90 degree channels and a calibrated "cement bond" tool with dual receiver three foot/five foot spacing located all but one of the 30 degree and all of the 60 and 90 degree channels.

The tools must be calibrated prior to their use and industry is encouraged to continue research to increase the sensitivity of the tools for mechanical integrity determinations.

The "Leak Test Well" was designed to generally correspond to a typical salt water disposal well used by the petroleum industry. It incorporates the use of surface casing, long string, tubing and packer. Additional modifications included two packers, a sliding sleeve on the injection tubing and a 2-3/8" tubing attached to the outside of the long string running to the surface. Flow into the well can be controlled so that the injected fluids are directed into the 2-3/8" injection tubing, or to the 2-3/8" leak string. Return flows can be controlled from the 2-3/8" leak string and also from the annulus of the 5-1/2" casing.

Some tests have been performed and a number are planned for the "Leak Test" well. These include: hydraulic conductivity of the injection zone; radial differential temperature log; temperature log; differential temperature log; radioactive tracer survey; noise log; flowmeter survey; annulus pressure changes resulting from temperature variances; volume-pressure relationship; "Mule Tail" test; effect of mud in the long string/surface casing annulus; helium leak test. Monitoring wells will be constructed to observe each of the three zones open to the "Leak Test Well."

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## ACKNOWLEDGMENTS

This paper reflects the work done to date on two unique research wells designed for testing methods for determining the mechanical integrity of injection wells. The successful design of the wells is due to the time and effort which an unusually able advisory panel was willing to devote to the project.

Grateful acknowledgment is made to the advisory group for their contribution:

Terry Anderson
Halliburton Cementing Services

Dick Angel
Phillips Petroleum

Al Bryant
Schlumberger Well Service

Mike Cantrell
Oklahoma Basic Economy Corp.

Cecil Hill
Baker Packers

Gene Littell
Littell and Randolph Engineering

Tal Oden
Oklahoma Corporation Commission

R. C. Peckham
USEPA, Region VI

Gary Batcheller, Schlumberger Well Service, and Alerdo Maffi, Tom Hansen Company, both made incalculable contributions to the project through their advice, encouragement and participation in a training course for EPA and State employees on October 16, 17, and 18, 1985.

# INTRODUCTION

Underground injection control regulations of the United States Environmental Protection Agency (USEPA) require that all injection wells demonstrate mechanical integrity for new wells prior to operation and all wells demonstrate at least every five years.

The regulations state that an injection 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.

The initial research project to examine the question of mechanical integrity was funded July 1, 1981. The three-phased project was to determine the state-of-the-art for mechanical integrity testing of injection wells and to test specific field methods to determine their adequacy.

The first phase of the project resulted in a report, "Methods for Determining the Mechanical Integrity of Class II Injection Wells." Although this report represented the state-of-the-art for determining mechanical integrity for Class II wells, the technology described may be applied to other classes of injection wells.

## MECHANICAL INTEGRITY TEST WELLS

The second and third phases of the project involved construction and testing of two wells designed to evaluate various tools and techniques used to determine mechanical integrity of injection wells. The test wells: a "Logging Well", and a "Leak Test Well" were designed for developing methods for testing the integrity of the tubing, casing and packer as well as locating fluid movement in channels behind the casing, and testing channels in the cement behind the casing; are located on a 110 acre site approximately 11 miles west of Ada, Oklahoma.

### Logging Well

The purpose of the Logging Well is to determine the present capability in the industry for evaluating the cement bond between the

cement/casing and cement/formation coupling in injection wells, and to provide a test facility for evaluating new tools developed for cement evaluation.

After much discussion among members of the advisory group, it was determined that the best method to simulate poor cement bonding, or channels in the cement, would be to attach water-filled PVC pipes to the outside of the casing. Thus, PVC pipe was attached to the outside of the casing to cover either 90°, 60°, 30°, or 6° of the 360° radial surface of the pipe (Figure 1).

Having installed the "channels" on the casing, attention was turned to a second vital factor in the completion of this well, the quality of the cement job. The planned cementing program was designed to provide the most favorable conditions for obtaining excellent bonding of the cement to the casing and and coupling of the cement to the formations so that the "channels" identified by the logging tools would be those purposely created for the project.

A thorough review of the logs run to evaluate the cement bonding indicates that about 60 percent of the well has good cement bonding and provides an excellent facility for determining the sensitivity of various down-hole cement evaluation techniques. The other 40 percent of the well provides an opportunity for testing techniques for repairing channels in cement, and for evaluating the success of the repair efforts.

The well specifications, along with a detailed description of the installation process, is provided in Appendix A.

*Cement Evaluation*

With the completion of the well, the actual testing portion of the project, determining the present capability for evaluating the cement, was ready to proceed. Contact was made with as many logging companies as possible to determine the type of tools that are being used for evaluating cement in a well, and run as many different tools as possible in the "Logging Well." At the initial contact with each company contracted to log the well, the construction and purpose of the well was fully explained, except for the location of the man-made channels. The company representative was also asked to provide a complete interpretation of the condition of the cement in the well, based on the information from their log, prior to their leaving the site.

Nine companies have produced 16 logs on the well. Two companies have refused to run a log on the well.

*Logging Tools*

Basically, two generations of logging tools have been run in the well: the "cement bond" tool, consisting of single transmitter/single

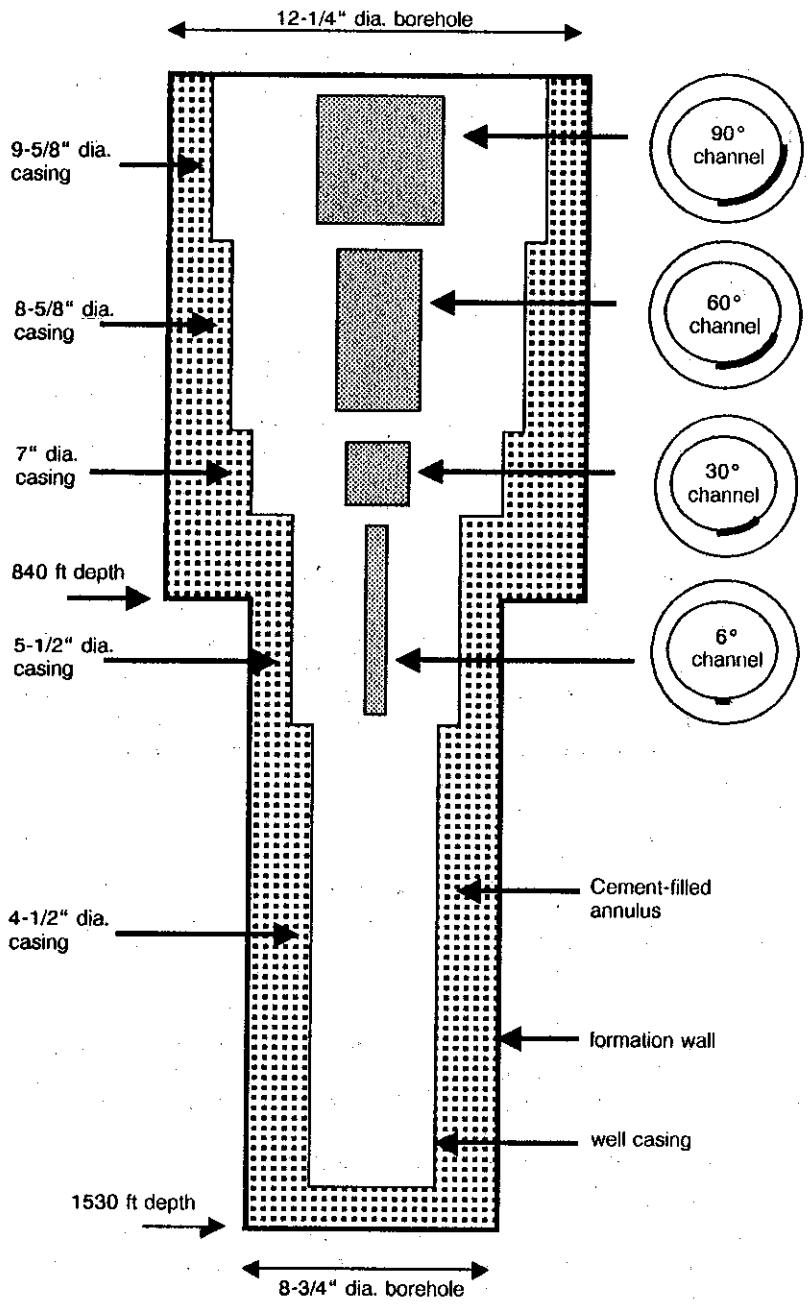


**Figure 1.** Logging well.

receiver or single transmitter/dual receivers; and the "cement evaluation" tool which has eight ultrasonic transducers.

The typical "cement bond" tool presents a log with the following data: gamma-ray and casing collar locator (CCL), which are included for depth control; transit time (TT), which measures the time it takes for a certain level sound wave to travel from the transmitter to the receiver; amplitude, which measures the strength of the first compressional cycle of the returning sound wave; and a graphic representation of the wave form, which displays the manner in which the received sound wave varies with time. This representation is called variable density log (VDL), seismic spectrum, or microseismogram, and is a function of the property of the material through which the signal is transmitted.

There are various transmitter/receiver spacings available, the most common being a single transmitter with a single receiver located three feet away (Figure 2). Other tools include the single transmitter/single receiver with four foot or five foot spacing, or a single transmitter/dual receiver with three foot/five foot spacing (Figure 3).

The "second generation" tools for determining the adequacy of cement bonding includes the use of a tool having eight ultrasonic transducers spiraled around it to survey the circumference of the casing (Figure 4). The information presented on the log from these tools includes: casing ovality, average casing I.D., casing collars, hole deviation, fluid velocity, eccentering of the tool, rotation of the tool, gamma-ray, maximum and minimum cement compressive strength, average of the energy returned to all eight transducers, and cement distribution around the casing.

*Log Interpretation*

The bonding of cement to casing can be measured quantitatively, but the bonding, or rather the coupling, of cement to the formation is only a qualitative estimate. Therefore, when attempting to evaluate cement in a well, it is extremely important to obtain as much information as possible.

The components of the sound wave that are of primary interest when analyzing a "bond log" are the casing, formation and fluid (mud) signals. Each medium has different characteristics, thus the sound waves will have different amplitudes, and velocities. Figure 5 indicates these wave forms and a composite signal.

A recommended approach to evaluating the "cement bond" log is to first determine the information available from the graphic representation of the wave form (VDL), then examine the amplitude curve to see if the two are in agreement. For example, if the casing diameter and transmitter/receiver spacing are known, the transit time for the casing arrivals can be predicted. Figure 6 is a chart that, for

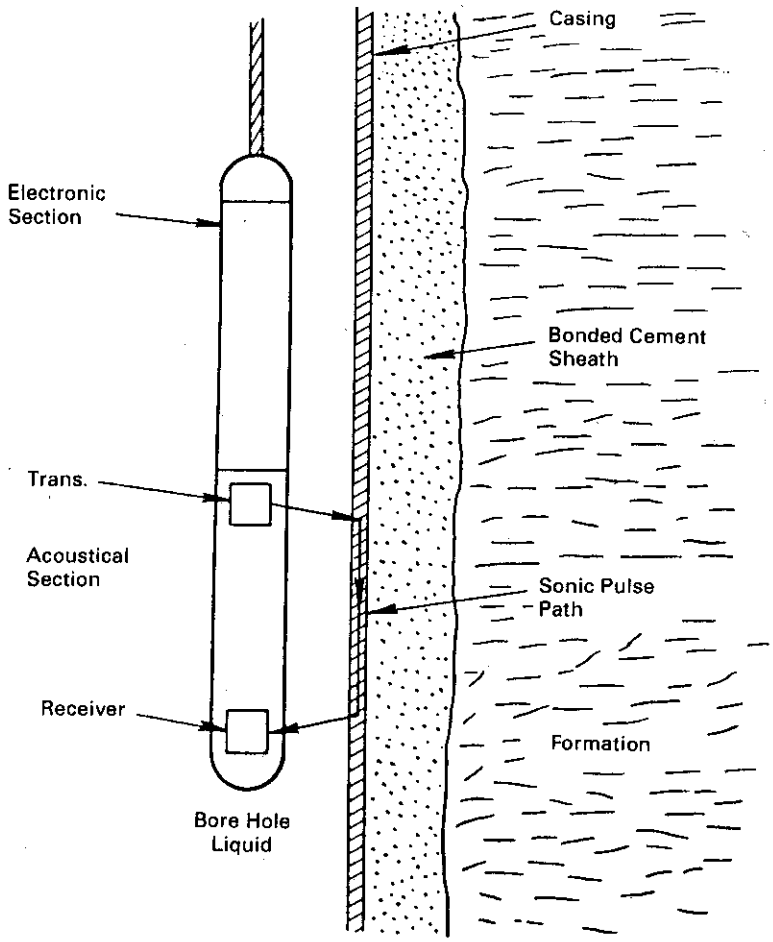


**Figure 2.** Cement Bond Tool - Single Transmitter/Receiver.

practical field or reference purposes, gives an idea of the approximate transit time for the casing signal for various tool spacing and casing I.D. By examining the VDL, the time, in microseconds of the first arrival, can be determined. This time can then be checked against the chart to determine if they are casing signals.

The fluid, or mud, wave has a velocity of about 189 microseconds/foot, and its arrival can be predicted if the tool spacing is known by multiplying the tool spacing by 189. The fluid wave has a destructive interference, thus when it enters the receiver, distortion of the wave occurs. Because of this, the only part of the VDL that is

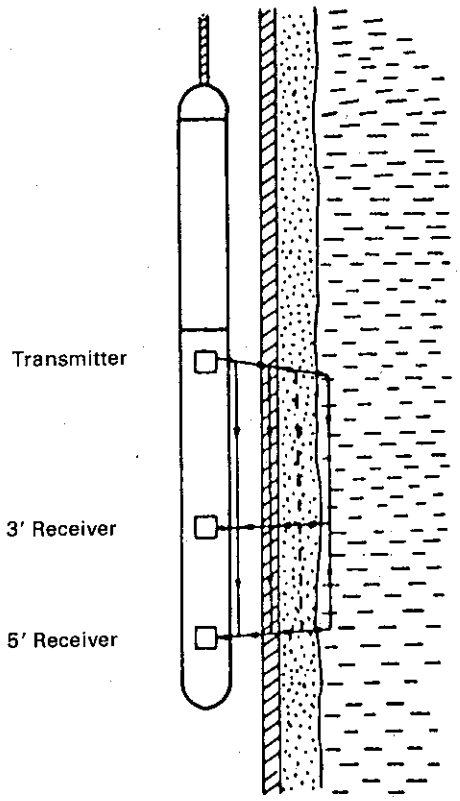


**Figure 3.** Cement Bond Tool - Single Transmitter/Dual Receiver.

useful for interpretive purposes is that part prior to the arrival of the fluid wave.

The "second generation" tools generate a pulse of untrasonic energy from each of the eight focused transducers that are arranged around the circumference of the tool. The strength and duration of the echoes reflected from the casing and cement are used to form an image of the cement distribution and quality around the casing. This information and the cement compressive strengths are two very useful pieces of data for evaluating the casing/cement bonding in a well.

As stated earlier, 16 different logs have been produced from the well. Appendix A containes a detailed comparison of specific sections of the well that have been logged by "first generation" tools with single transmitter/receiver, three-, four- or five-foot spacing; amd the "second generation" ultrasonic logging tool.

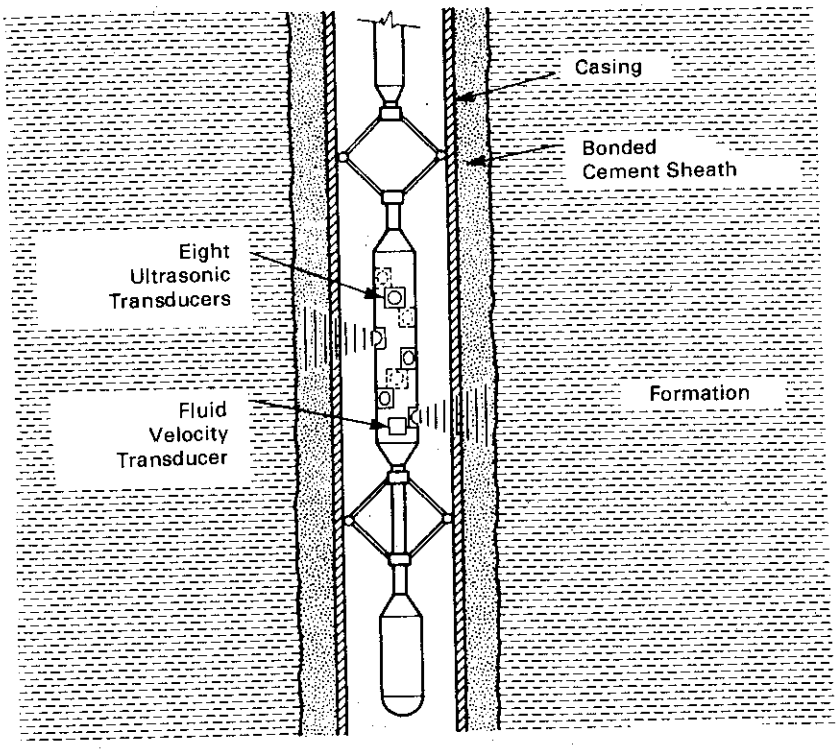


**Figure 4.** Second Generation Tool.

*Well Logging Conclusions and Recommendations*

***Well Completion***

Greater care must be exercised in planning the cement job and in carrying out that plan when cementing injection wells, especially Class I wells where cement is to be circulated to the surface around the long string. The plan should include equipment and activities that will enhance the possibility for obtaining the best cement bonding possible. This should include the use of a caliper log to determine exact hole size to better estimate the volume of cement necessary to complete the well; properly conditioned drilling mud prior to beginning the cementing operation; centralizers, to ensure that the casing is centered in the hole; pre-flush, to help clean out the hole prior to

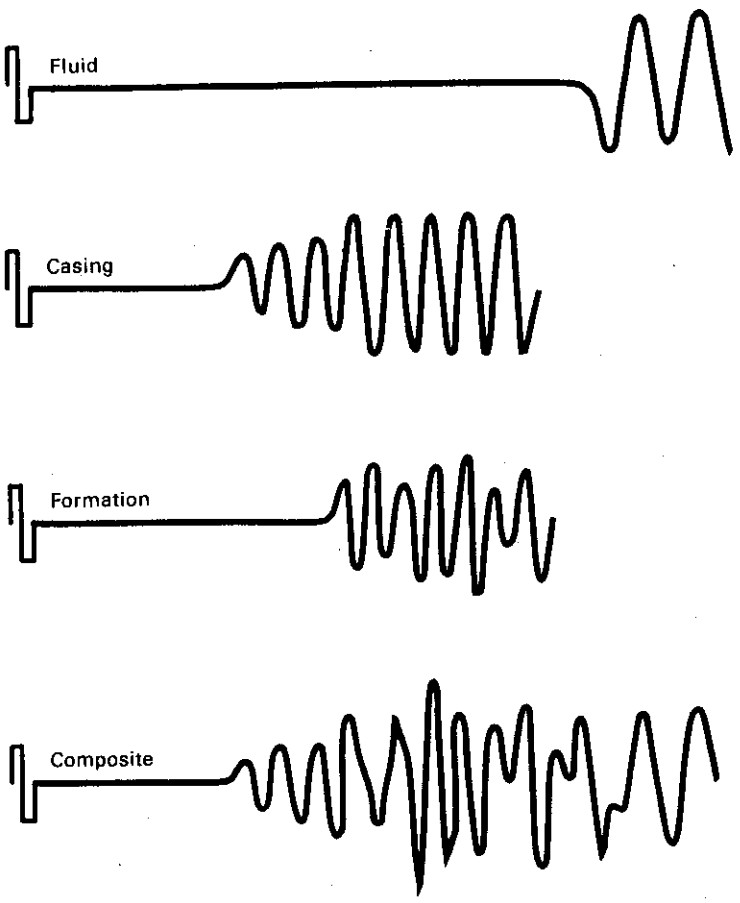


**Figure 5.** Composite wave form.

| | | A | |
|---|---|---|---|
| | 3 | 4 | 5 |
| 4 | 235 | 292 | 349 |
| D" 5 | 250 | 307 | 364 |
| 6 | 265 | 322 | 379 |
| 7 | 280 | 337 | 394 |

A - Receiver spacing D" - Casing diameter

**Figure 6.** Field reference transit time.

pumping cement; rotating and/or reciprocating the pipe during the cementing operation to further aid in cleaning out the hole; and at least 100 percent excess cement. The experience in cementing the "Logging Well" indicates that in those areas where the greatest volume of cement flowed past, the cleaner the hole and the better the cement bond, thus the use of 100 percent excess cement will enhance the probability of a good cement job throughout the casing length.

In the "Logging Well," although cement was circulated to the surface, after the cement set for 72 hours, the top of cement behind the casing was 132 feet below land surface. This "fall back" of the cement behind the casing must be monitored and corrected so that there is cement fill-up behind the casing to the surface of the ground.

### *Logging Equipment*

None of the logging tools presently available located any of the six degree channels in the "Logging Well." The "second generation" tools located all of the 30, 60, and 90 degree channels that were designed into and could be identified in the well. A calibrated single transmitter/dual receiver "cement bond" tool with three foot/five foot spacing located the 60 and 90 degree channels and all but one of the 30 degree channels. The other "cement bond" tools with single transmitter/single receiver three foot, four foot, or five foot spacing presented very inconsistent results.

The three foot spacing is the best currently available for measuring and evaluating the amplitude of the first compressional arrival and the attenuation of this signal is a measure of the bonding of the cement to the casing. However, this spacing is not satisfactory for determining data on or evaluating the relationship of the cement to the formation. Five foot spacing between the transmitter and receiver is the best currently available for evaluating the relationship of the cement to the formation, but it is not accurate for determining

bonding to the casing. Four foot spacing is being used, however it does not have satisfactory resolution for evaluating the relationship of the cement to either the casing or formation.

The significant fact remains that none of the tools located channels smaller than 30 degrees in the well. Such channels represent a significant avenue for movement of fluid and methods must be developed to locate these and even smaller channels. It is recommended that the logging industry continue research efforts toward increasing the sensitivity of the logging tools.

The research conducted on the "Logging Well" indicates that with the presently available tools, the ideal approach for evaluating the cement in an injection well is to run both the "second generation" tool and a calibrated "cement bond" tool with single transmitter/dual receiver three foot/five foot spacing. This combination gives the most information for interpretive purposes.

An alternative to this approach is the use of either the "second generation" tool or a calibrated "bond tool" with single transmitter/dual receiver three foot/five foot spacing. The "second generation" tool gives no information on the cement/formation coupling, but gives excellent information on the cement/casing bonding and its presentation allows for easy interpretation. The "cement bond" tool provides information on both casing/cement bonding and coupling to the formation, but is somewhat harder to interpret and may be less sensitive in some specific situations.

Calibration of both tools is imperative for reliable data to be produced. The size and weight of the casing must be available for use with the "second generation" tool. A standard shop calibration of the "cement bond" tool is essential to its use and must be included for there to be any hope that reliable information can be obtained. Quality control on the "cement bond" tools can be included, to some degree, on site, in that certain checks can be made to determine whether or not the tool is working properly.

Some of the checks that can be made include:

1. If the well contains free pipe, the chevron effect must be obvious. The chevron effect is the "W" seen opposite casing collars in free pipe. Figure 7 indicates a bond log with free pipe. Note the well developed chevron effect opposite the casing collars.

2. In free pipe, certain casing diameters call for certain amplitude readings. For example, for 5 inch (I.D.) casing the amplitude should read about 74 millivolts (mv); 7 inch - 60 mv; 8 inch - 55 mv; 9 inch - 30 mv-35mv. Such information can be used to determine if the tool has been calibrated. Figure 7 indicates an amplitude reading of over

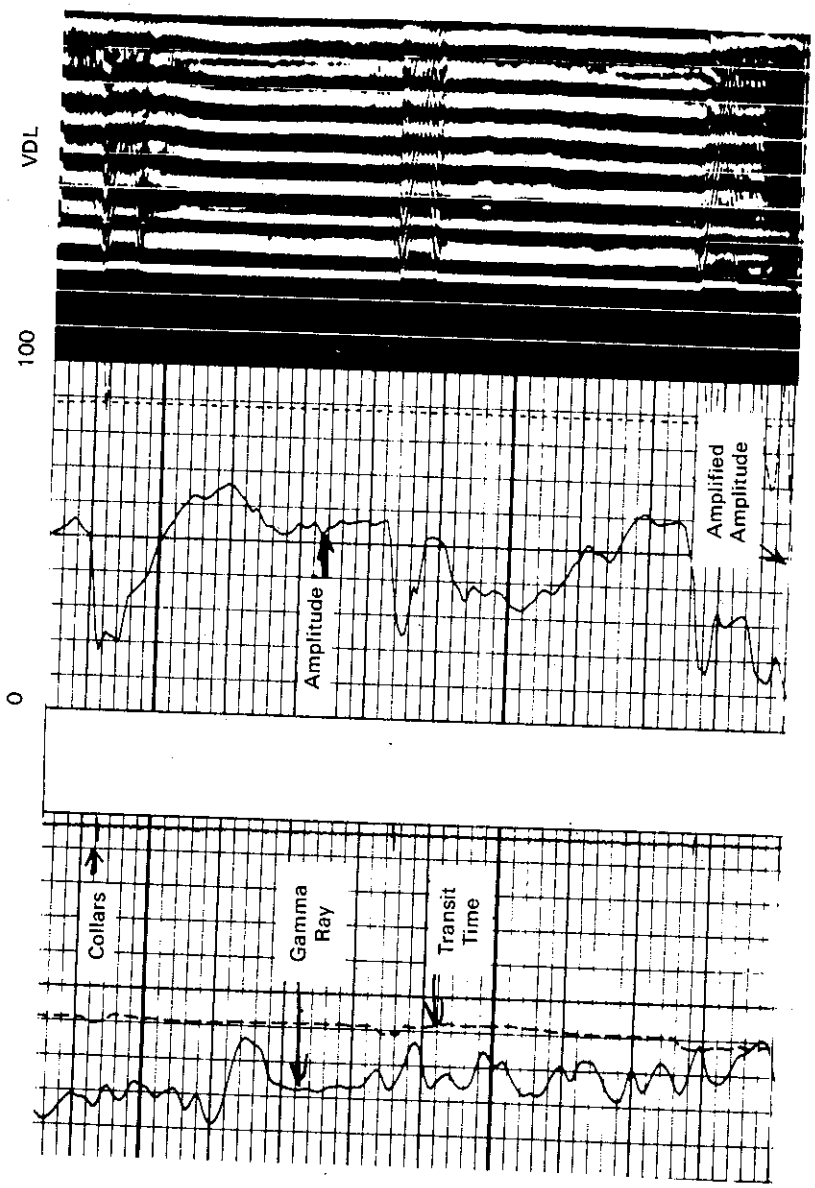


**Figure 7.** Amplitude, chevron and free pipe.

60mv in 9 inch free pipe. This indicates that the tool was not calibrated.

3. In free pipe, the transit time from a properly centered tool should be constant, except for the influence of the casing dollars. In Figure 7, the decrease in transit time (immediately below the arrow) and the corresponding decrease in amplitude, indicates a slightly eccentered tool. Figure 8 also indicates free pipe. Note, however, the wavy free pipe signal on the VDL and the significant drift of the transit time (over one-half of a chart division). This indicates an improperly centered tool.

4. The fluid wave should be visible on each wave form presentation (VDL). If the fluid wave is not visible, this indicates a low response tool and its use should be questioned.

An API committee is presently working on standardizing a calibration system. This work should be encouraged and continued until an adequate system is developed that can be used throughout the industry.

### *Log Interpretation*

A significant problem that became apparent during the research efforts on the "Logging Well" was the inability of some logging company personnel to interpret the logs they produced. Several companies had good equipment, but on site personnel apparently did not have sufficient knowledge of the equipment to properly operate the system or interpret the log. This is a critical concern if these tools are to be used to evaluate the cement in an injection well. The logging company, injection well owner, or regulatory agency must have trained personnel that are capable of evaluating a log to determine as much information as possible on the quality of the cement behind each casing string.

## Leak Test Well

The purpose of the "Leak Test Well" is to provide a facility to develop methods for testing the integrity of the tubing, casing and packer and for testing the capability of various down-hole tools to detect fluid movement behind the casing.

The design of the well generally corresponds to a typical salt water disposal well used in the oil and gas industry. That is, it includes the use of surface casing, long string, tubing, and packer. The deviation from the norm in this well includes two packers and a sliding sleeve on the injection tubing and a 2-3/8" tubing attached to the outside of the long string and running to the surface (Figure 9).

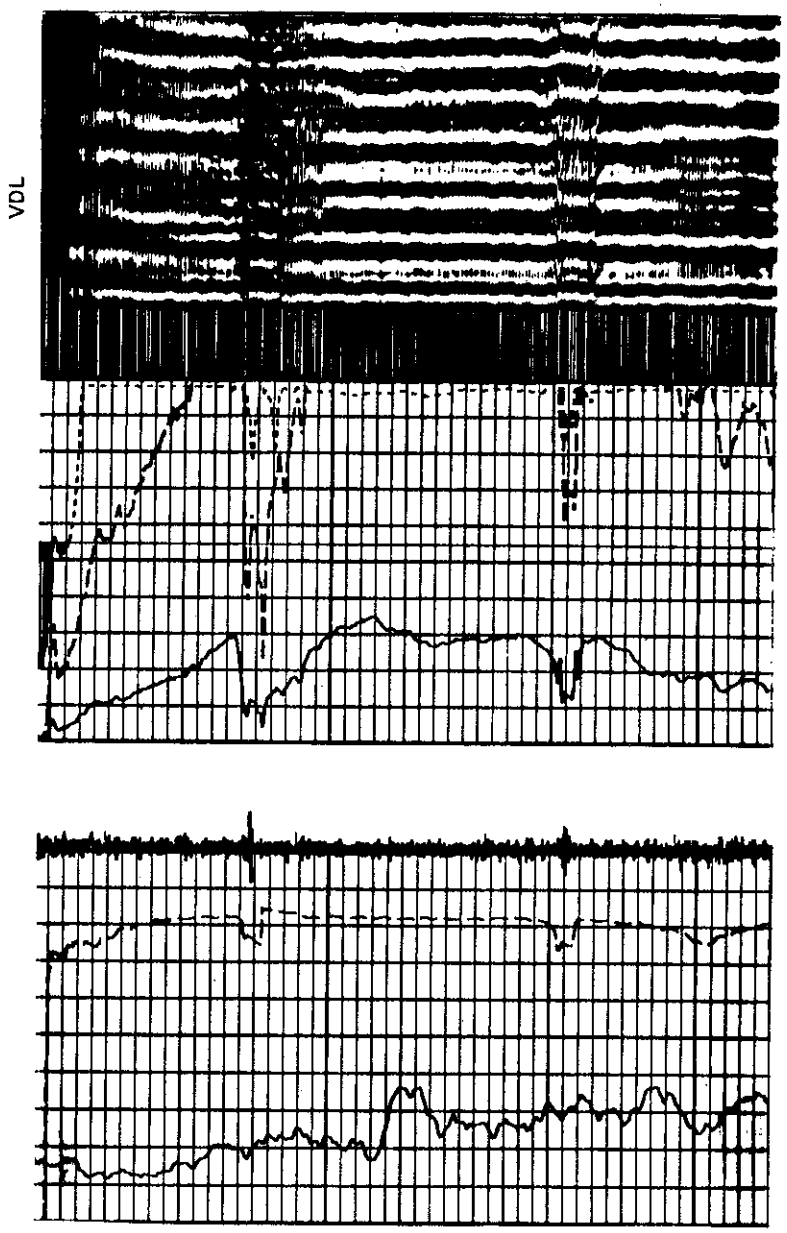


**Figure 8.** Tool not centered.

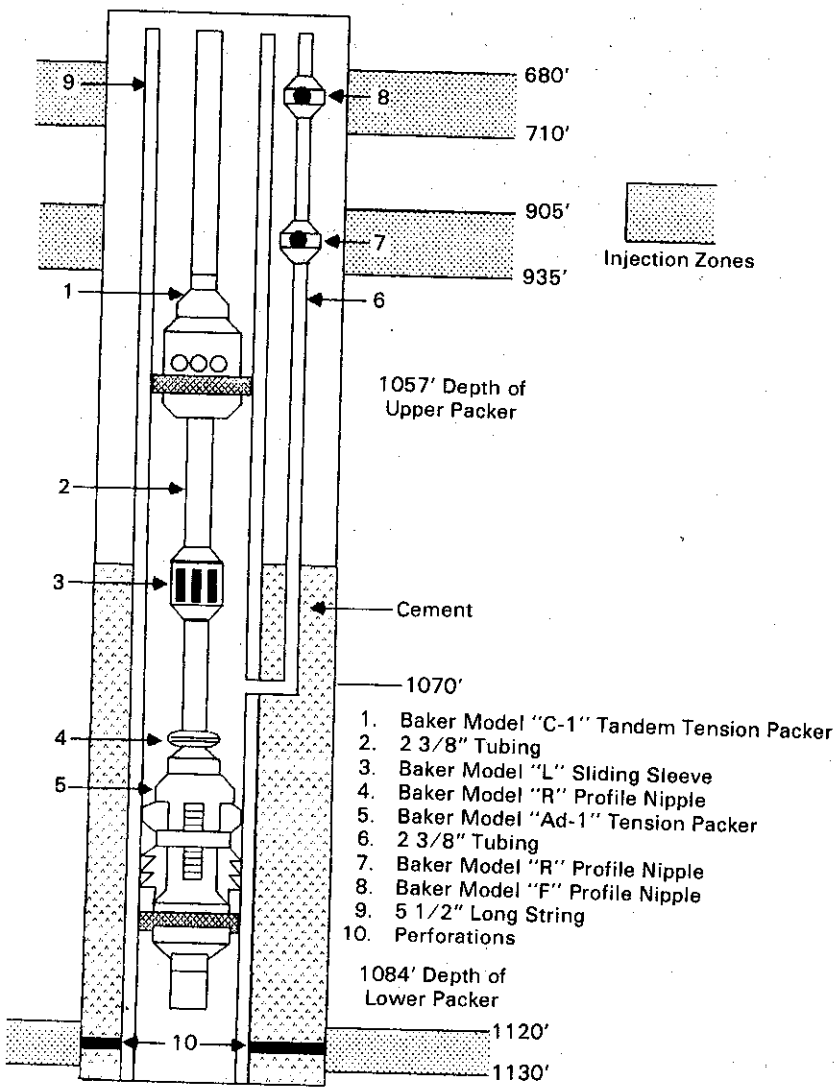


**Figure 9.** Leak test well.

Detailed discussion on well design and installation is provided in Appendix B.

Flow into the well can be controlled so that the injected fluids are directed into the 2-3/8" injection tubing, or to the 2-3/8" leak string. Returned flows can be controlled from the 2-3/8" leak string and also from the annulus of the 5-1/2" casing (Figure 10).

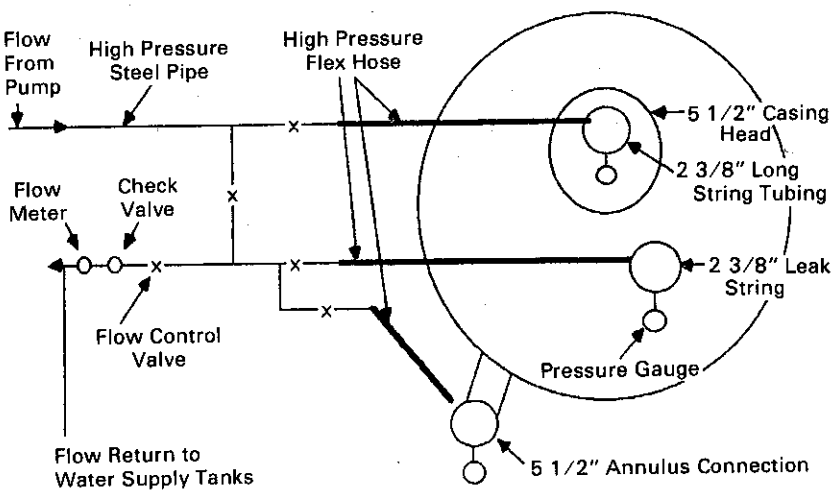


**Figure 10** Injection well head and flow lines.

Monitoring wells will be constructed to each of the zones open to the "Leak Test Well." One well will be drilled to a depth of 680 feet. This is open to injection through a Baker Model "F" profile nipple in the 2-3/8" leak tubing. A second well will be drilled to a depth of 935 feet. This is the second zone open to flow through a Baker Model "R" profile nipple. A third well is to be drilled 1,130 feet deep to monitor the pressure changes in the injection zone.

A number of tests have been conducted or are planned for the "Leak Test" well. Some of these include:

| Test | Date Completed |
|---|---|
| 1. Hydraulic conductivity of the injection zone | 5/13/86 |
| 2. Radial differential temperature log | 4/27/87 |
| 3. Temperature log | Planned |
| 4. Differential temperature log | Planned |
| 5. Radioactive tracer survey | 5/19/86 |
| 6. Noise log | 4/6/87 |
| 7. Acoustic cement bond tool | 1/23/87 |
| 8. Nuclear activation tool | 1/24/87 |
| 9. Gas pressure test | 2/12/87 |
| 10. Down-hole TV | 1/27/87 |
| 11. PDK-100 tool (oxygen activation) | 4/8/87 |
| 12. Flowmeter survey | Planned |
| 13. Annulus pressure changes due to temperature changes | Planned |
| 14. Volume/pressure relationship | Planned |
| 15. Effect of mud in the long string/surface casing annulus | Planned |
| 16. Helium leak test. | Planned |
| 17. "Mule tail" test | Planned |

## CONCLUSIONS

The viability of deep well injection as a waste management alternative rests on the ability to emplace wastes in geologic formations beneath and isolated from underground sources of drinking water. Wastewater injected under pressure or by gravity into wells may escape through leaks in the well casing caused by mechanical failure within the well or by migration of wastewater between the well's outer casing and wellbore because of faulty cementing. Although technology is available to construct and operate injection wells that meet mechanical integrity criteria, technology for determining injection well mechanical integrity must be tested and proven to insure that sound decisions are made and that underground sources of drinking water are protected.

No one test provides sufficient information to make a determination of the mechanical integrity of an injection well. Rather, this determination is made from a combination of tests, each providing pieces of information to be evaluated together in making an informed judgement regarding the mechanical integrity of an injection well.

The research facilities described in this article offer industry, state regulatory agencies and EPA a unique capability to test and evaluate a variety of methods for determining mechanical integrity. Such testing can improve the confidence of industry and permitting agencies in approved methods and can speed the acceptance of new methods that may be developed.

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# APPENDIX A

# LOGGING WELL DESIGN SPECIFICATIONS AND INSTALLATION PROCEDURES

## LOGGING TEST WELL MATERIAL SPECIFICATIONS:

| Casing | Weight | Grade |
|---|---|---|
| 3 joints of 9-5/8" | 53.5#/ft | N-80 |
| 3 joints of 9-5/8" | 36.0#/ft | K-55 |
| 8 joints of 8-5/8" | 24.0#/ft | J-55 |
| 4 joints of 7" | 23.0#/ft | K-55 |
| 2 joints of 5-1/2" | 23.0#/ft | N-80 |
| 3 joints of 5-1/2" | 17.0#/ft | J-55 |
| 3 joints of 5-1/2" | 15.5#/ft | J-55 |
| 2 joints of 4-1/2" | 13.5#/ft | N-80 |
| 4 joints of 4-1/2" | 11.6#/ft | J-55 |
| 5 joints of 4-1/2" | 9.5#/ft | J-55 |

| Equipment | Size | Grade |
|---|---|---|
| Swage nipple | 5-1/2" x 4-1/2" | K-55 |
| Swage nipple | 7" x 5-1/2" | J-55 |
| Swage nipple | 8-5/8" x 7" | J-55 |
| Swage nipple | 9-5/8" x 8-5/8" | J-55 |
| Swage nipple | 9-5/8" x 5-1/2" | J-55 |
| 10 centralizers | 4-1/2" | |
| 7 centralizers | 5-1/2" | |
| 3 centralizers | 7" | |
| 7 centralizers | 8-5/8" | |
| 5 centralizers | 9-5/8" | |

## DETAILED DESCRIPTION OF WELL CONSTRUCTION

On August 14, 1984, the process of preparing the "channels" was begun. PVC pipe, either 3/4" or 1/2" in diameter, was sealed on one end, filled with water saturated with boric acid and capped. The next step was to attach the PVC pipe to the outside of the casing so that the "channel" would cover either 90°, 60°, 30°, or 6° of the 360° radial surface of the pipe (Figure 1). This was accomplished by attaching the PVC pipe to the surface of the casing using fiberglass cloth and epoxy resin. Three layers of fiberglass were used to ensure that the PVC pipe was securely sealed and attached to the casing

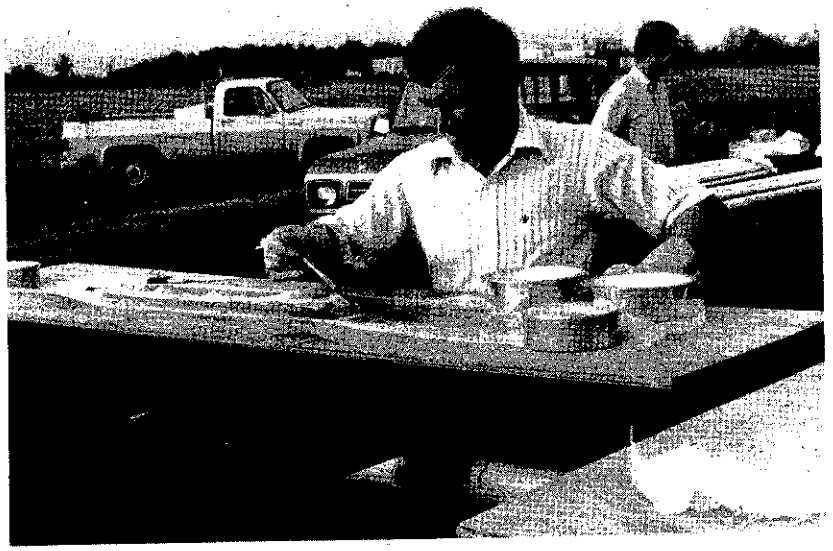
(Figures A-1 to A-4). This phase of the project was completed on September 17, 1984.

The casing was then wrapped with heat tape and insulation to prevent freezing of the "channels" while awaiting the availability of the drilling rig.

The driller began moving the rig to the site on December 13, 1984. Rigging up continued on the 14th and 15th and drilling began at 2:30 p.m. on December 15, 1984. The procedure followed and the date each step was accomplished are indicated below:

| Activity | | Date Completed |
|---|---|---|
| 1) | Prepare site (Baulch Drilling Company) | 12/13/84 |
| 2) | Move in rig and rig up | 12/15/84 |
| 3) | Drill 15" hole to 40', set 13-3/8" conductor pipe (OK Cement, 35 sx) | 12/15/84 |
| 4) | Drill 8-3/4" hole to 1530'. Collect drill cuttings every 10' starting at 100' | 12/18/84 |
| 5) | Condition hole for logging | 12/18/84 |
| 6) | Run Dual Induction Laterolog, Gamma Ray, Compensated Neutron, Compensated Density, and B.H.C. Sonic Log (Gearhart) | 12/18/84 |
| 7) | Ream 12-1/2" hole to 758' | 12/20/84 |
| 8) | Clean out hole to TD, condition for setting casing | 12/20/84 |
| 9) | Set casing | 12/20/84 |
| 10) | Run 2-3/8" tubing and sting into Baker Duplex Cement shoe. Condition hole for cementing. | 12/20/84 |
| 11) | Cement casing (Halliburton, 700 sx. 50/50 Posmix) | 12/20/84 |
| 12) | Remove tubing, flush out hole | 12/20/84 |
| 13) | Weld steel plate between 9-5/8" and 13-3/8" casing. Install 9-5/8" x 5-1/2" swage nipple on 9-5/8" casing. Screw locking cap on swage. | 12/27/84 |
| 14) | Install rock pad and cement slab | 09/10/85 |

The design of the "Logging Well" presumed that the "channels" would remain in place during the process of setting and cementing the casing. The driller took special precautions when moving the pipe from the pipe racks to the rig, and during the pipe setting process to



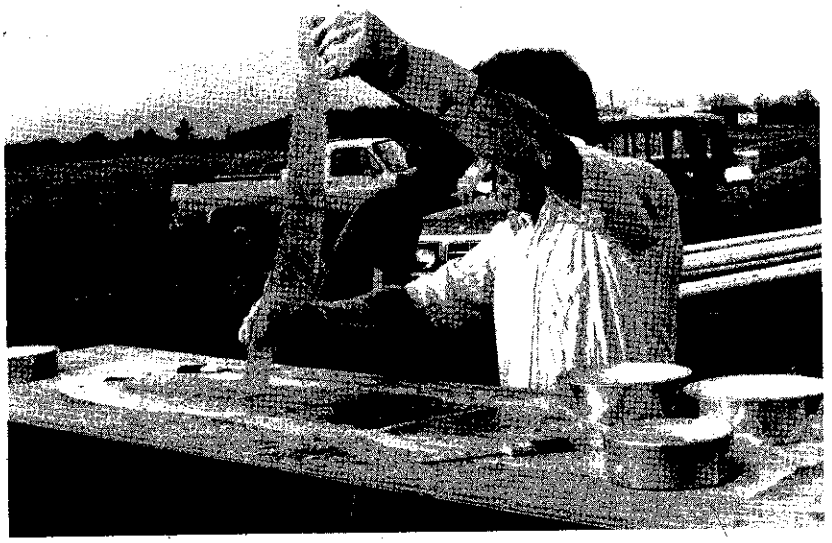


**Figure A-1.** Preparing fiberglass with epoxy resin.

**Figure A-2.** Applying initial fiberglass layer.

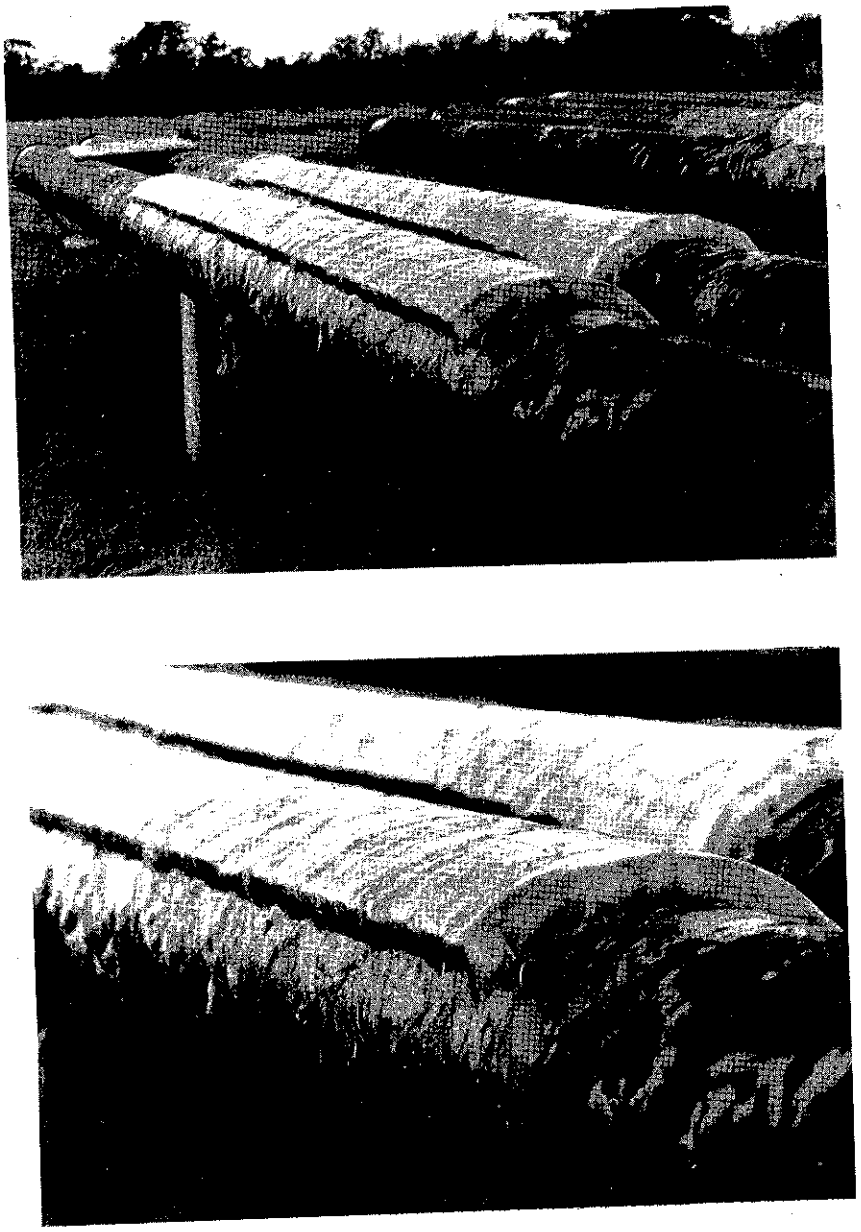


**Figure A-3.** Completed channel - prior to using wire brush to remove excess.

**Figure A-4.** Removing excess fiberglass with wire brush.

ensure that this was the case. No problems were encountered during the entire casing setting and well cementing operation, thus there was a high degree of confidence that the channels were not damaged and were in place as designed. Later review of logs run on the well reinforced this confidence.

*Log Interpretation*

Figures A-5, A-6 and A-7 are portions of logs from the "Logging Well" that compare single transmitter/single receiver with either three, four, or five foot spacing; single transmitter/dual receiver with both three foot and five foot spacing; and the "second generation" logs. Each interpretation is based solely on information from the log being interpreted.

Figure A-5a indicates a log section from a tool with single transmitter/ single receiver, three foot spacing. The fluid wave should enter the receiver at about 567 microseconds, however, it is indistinguishable on this log. Casing signals are present in the upper part of the VDL, but no other interpretation can be made. The amplitude curve indicates poor bonding in the upper part of the section, which seems to agree with the VDL, and casing/ cement bonding throughout the remainder of the section.

Interpretation: Excellent casing/cement bonding throughout the section with a possible channel or microannulus in the upper part of the section. Coupling to the formation cannot be determined.

Figure A-5b is the same section from a single transmitter/single receiver tool, with four foot spacing. The fluid wave should enter the receiver at about 756 microseconds, as indicated on the log. Casing signals may be present in the upper part of the section, although the signals are weak. The amplitude curve indicates a problem in the upper part and casing/ cement bonding for the remainder of the section.

Interpretation: Excellent casing/cement bonding throughout the section with a possible channel or microannulus in the upper part of the section. No coupling to the formation.

Figure A-5c is the same section from a tool with single transmitter/ single receiver, five foot spacing. The fluid wave should enter the receiver at about 945 microseconds. In this case, the fluid wave is pushed far enough to the right to allow the formation signals to be seen. The VDL indicates formation signals throughout the section, and some casing signals in the upper part of the section. The amplitude curve indicates a problem in the upper part with casing/cement bond throughout the remainder of the section.

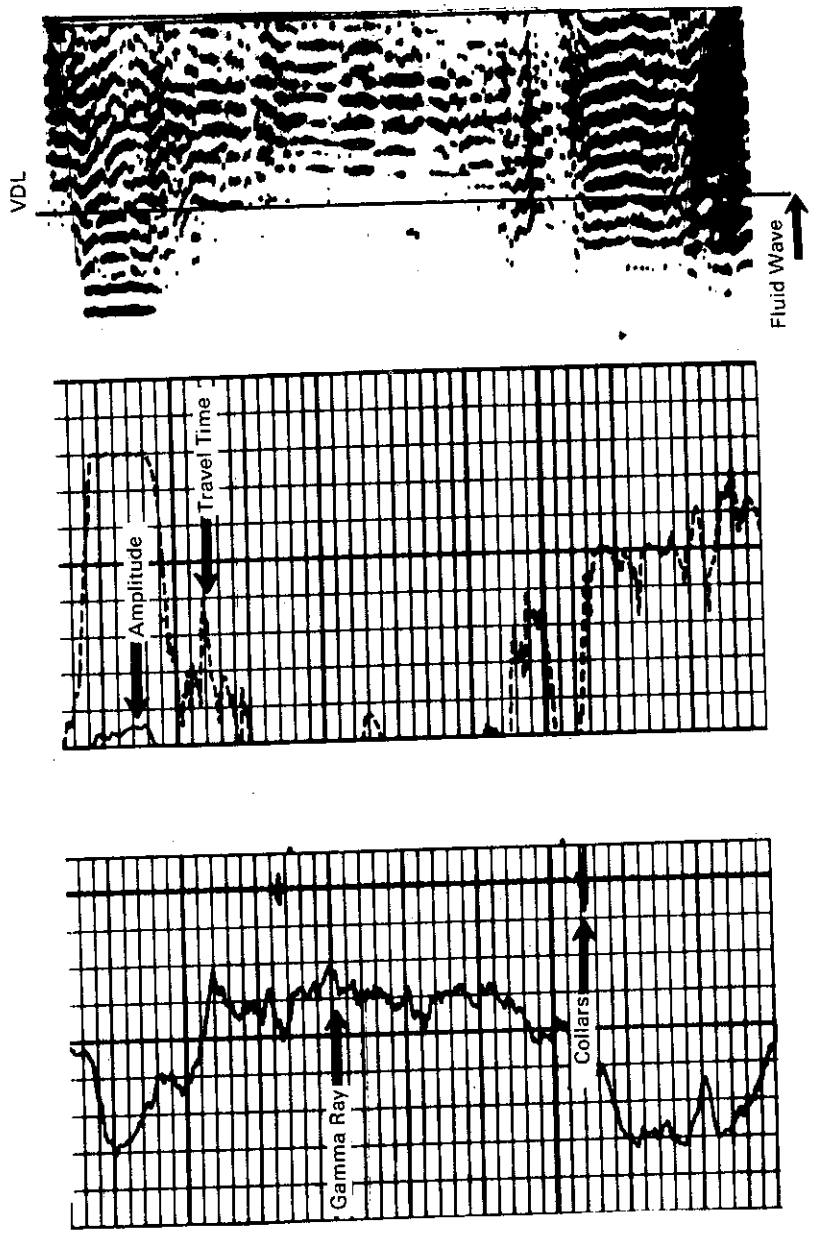



**Figure A-5a.** Single receiver 3-foot spacing.

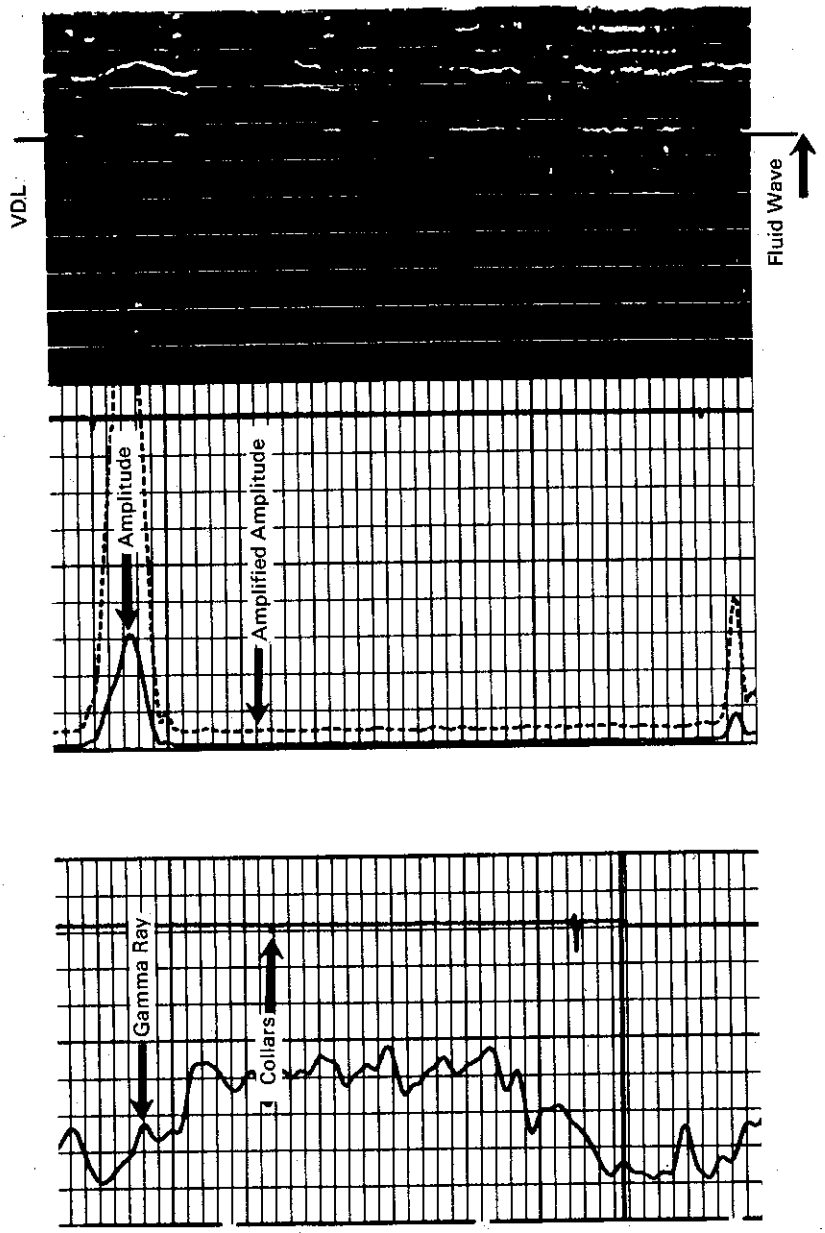



**Figure A-5b.** Single receiver 4-foot spacing.

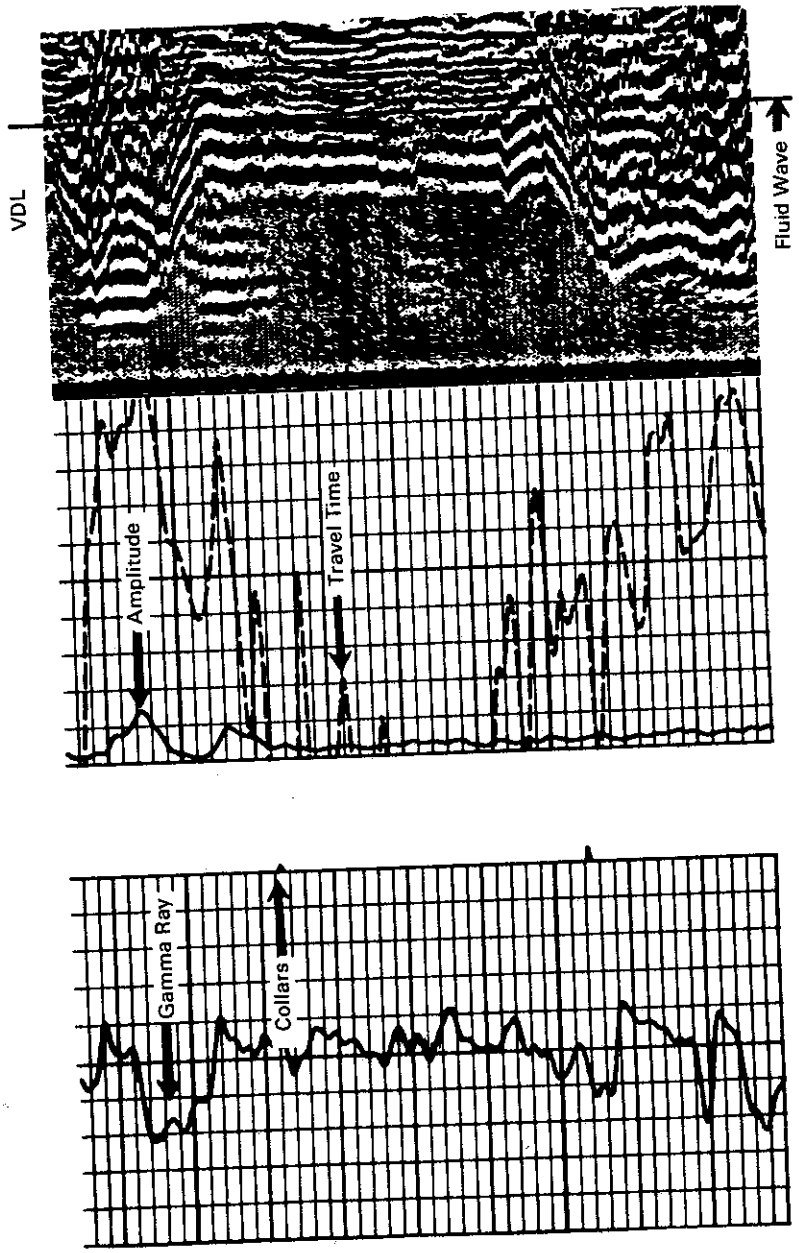



**Figure A-5c.** Single receiver 5-foot spacing.

Interpretation: Excellent casing/cement bonding throughout the section with a possible channel or microannulus in the upper part of the section. Possible coupling of cement to the formation.

Figure A-5d is the same section from a tool with single transmitter/ dual receivers and a three foot/five foot spacing. The VDL shows formation signals throughout the section and casing signals in the upper and lower parts of the section. The amplitude curve indicates a problem in the upper part with casing/cement bonding indicated throughout the remainder of the section.

Interpretation: Excellent casing/cement bonding throughout the section with either channels or microannuli in the upper and lower parts of the section. Possible coupling to formation.

Figure A-5e is the same section from one of the "second generation" logs. The white areas on the bond image portion of the log indicate the presence of poor casing/cement bonding. The minimum compressive strength curve also indicates some problems in three areas that coincide with the white areas on the bond image portion of the log.

Interpretation: Excellent casing/cement bonding with three channels or microannuli in the upper, middle and lower parts of the section. No information is available on formation coupling.

A second comparison of the different logging tools run in the "Logging Well" is shown in the Figure 6 series. Figure A-6a is a log section from a tool with single transmitter/single receiver, three foot spacing. The fluid wave should enter the receiver at about 567 microseconds, however, it is not distinguishable on this log. There may be formation signals in the presentation, however they are not distinctive, making it difficult to determine the character of the log. The amplitude curve only registers in two places on the log, and the transit time curve is not definitive.

Interpretation: Excellent casing/cement bonding throughout the section.

Figure A-6b is the same section from a tool with single transmitter/ single receiver, four foot spacing. The fluid signal is very strong, with the VDL indicating casing/cement bonding but no formation coupling. The amplitude curve indicates casing/cement bonding.

Interpretation: Excellent casing/cement bonding, no formation coupling.

Figure A-6c represents a log from a tool with single transmitter/single receiver with five foot spacing. It shows very clear formation signals on the VDL, with one area near the center of the

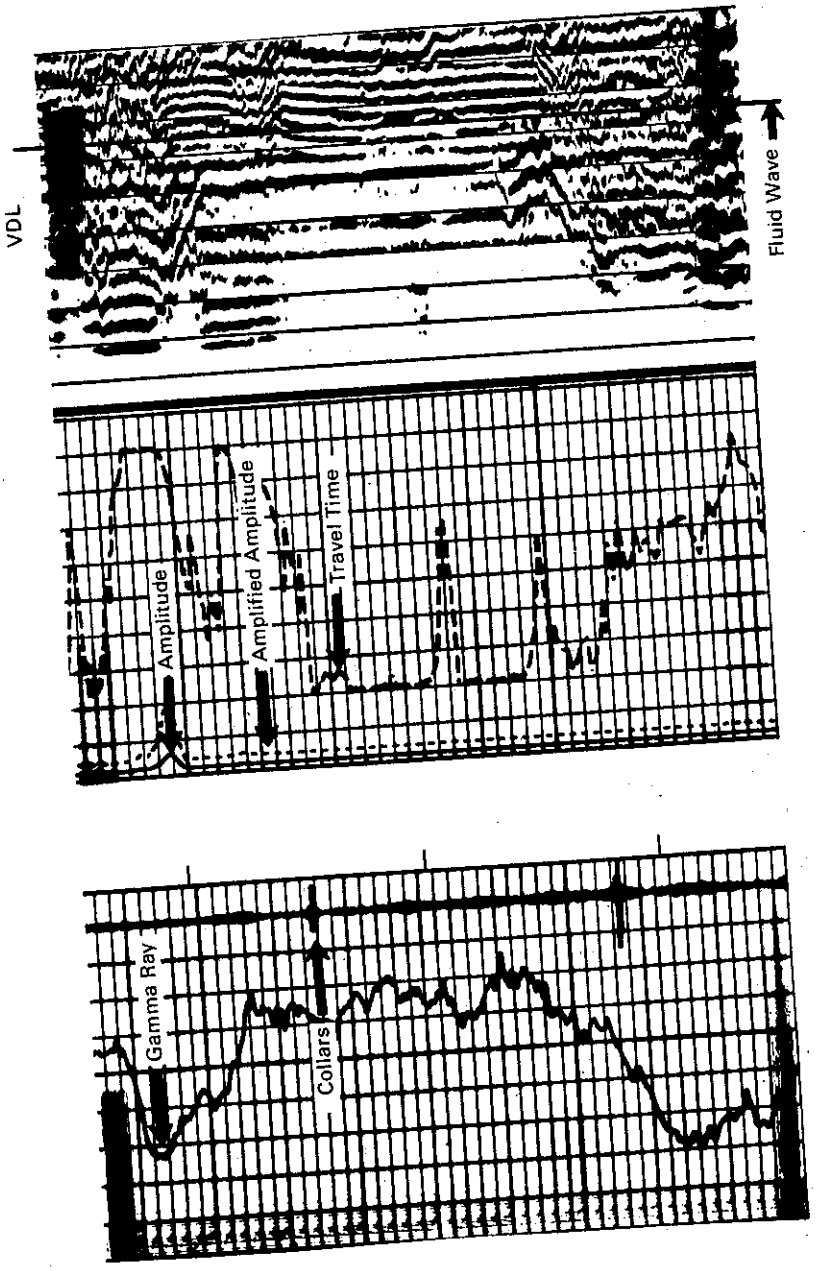



**Figure A-5d.** Dual receiver 3-foot/5-foot spacing.

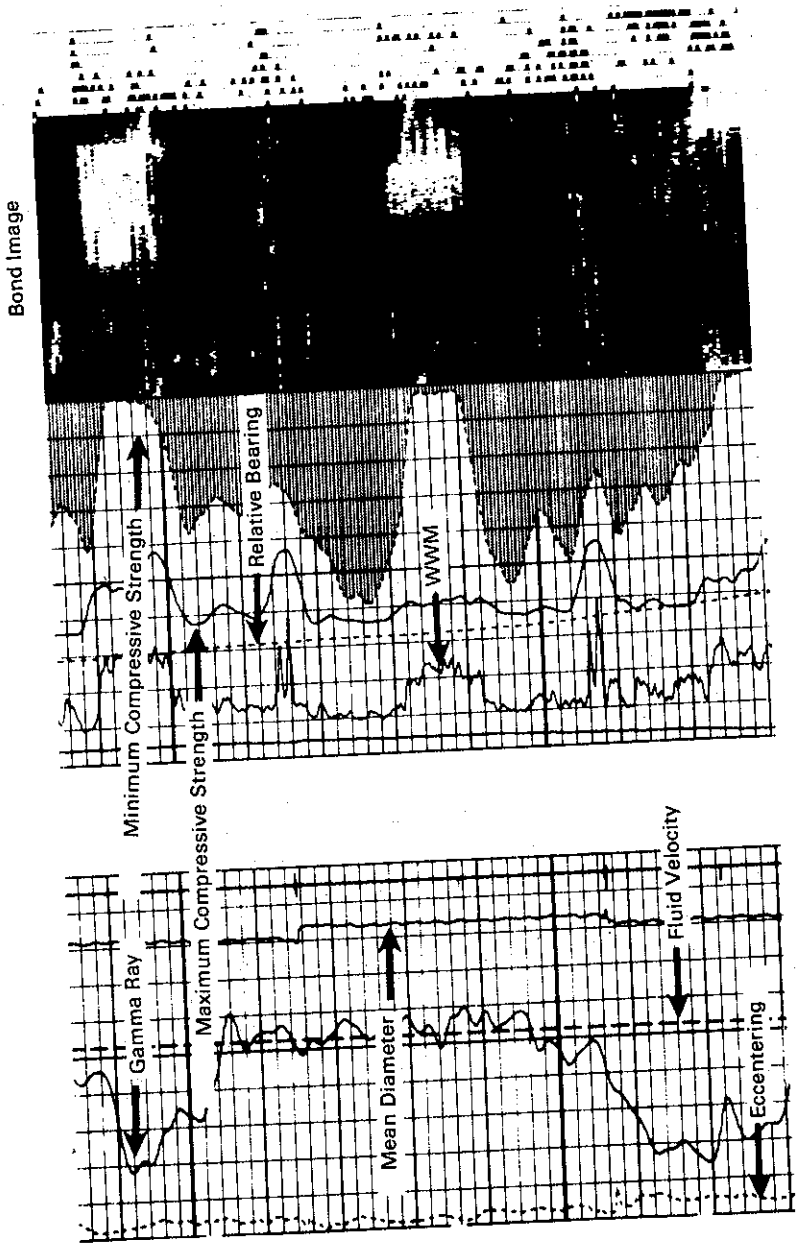



**Figure A-5e.** Siecond generation log - Company A.

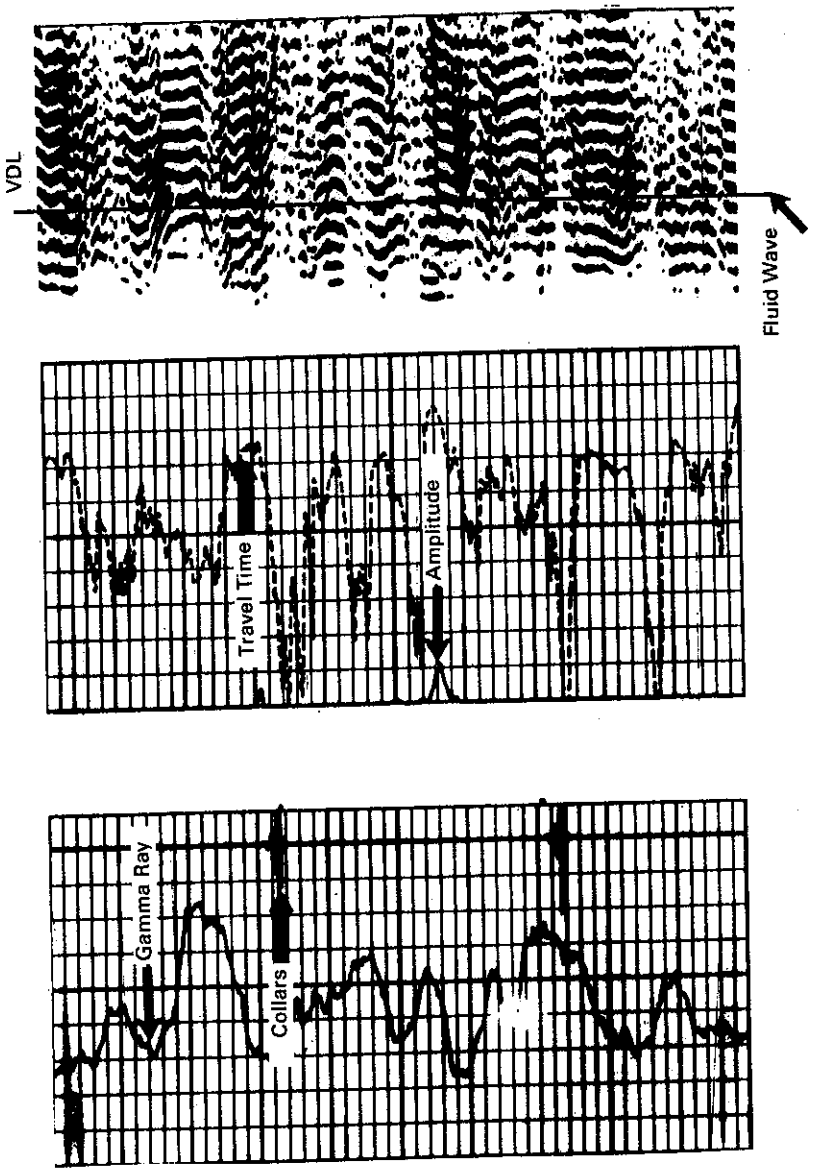



**Figure A-6a.** Single receiver 3-foot spacing.

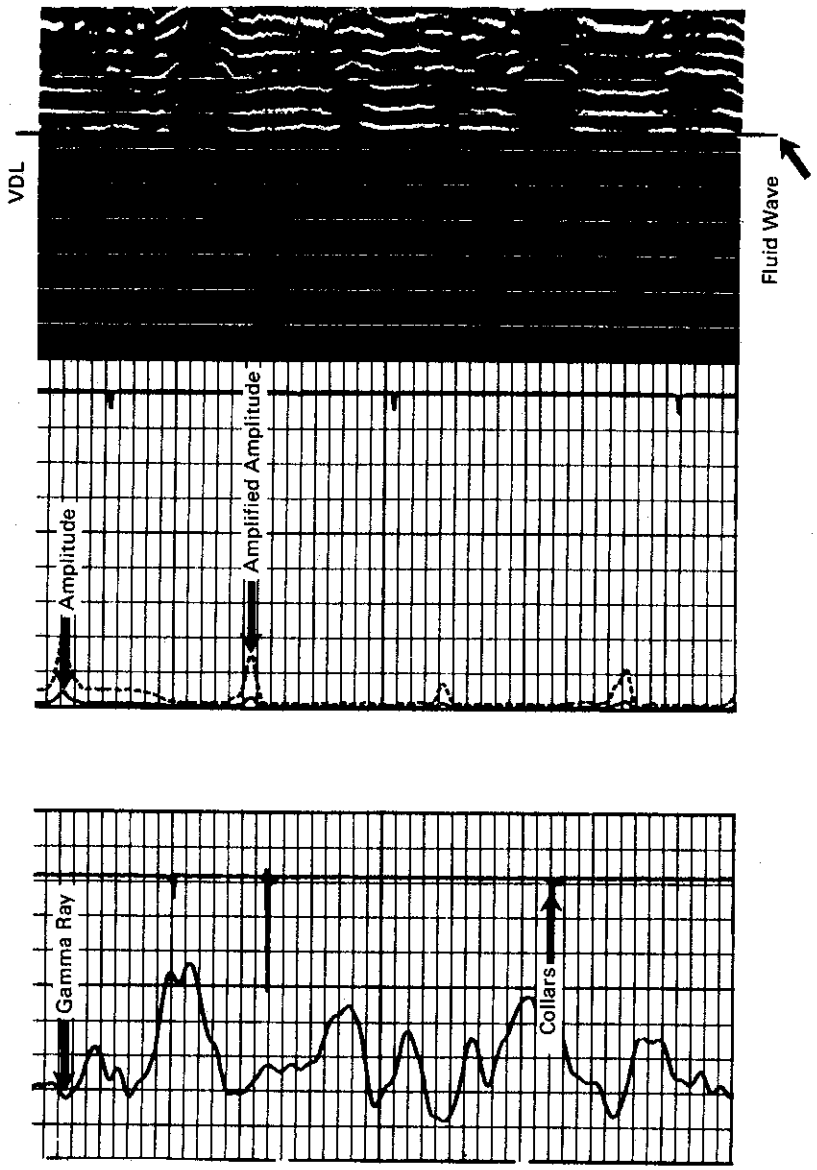



**Figure A-6b.** Single receiver 4-foot spacing.

section showing casing signal. The amplitude curve shows casing/cement bonding, with a possible problem in the center of the section.

Interpretation: Good casing/cement bonding with the possibility of a channel or microannulus in the middle of the section. Formation signals indicate coupling to the formation.

Figure A-6d represents a log from a tool with single transmitter/dual receivers with three foot/five foot spacing. The VDL shows formation signals throughout the section and definite casing signals near the middle and in the lower part of the section. The amplitude curve indicates cement/casing bonding, with a very slight response in the middle of the section.

Interpretation: Excellent casing/cement bonding with the possibility of channels or microannuli in the middle and lower parts of the section. Formation signals indicate coupling of the formation to the casing.

Figure A-6e is a log of the same section of the hole from a "second generation" tool. The bonding display indicates two channels or microannuli, one in the middle and one in the lower section. The average cement strength curve correlates with the bonding display.

Interpretation: Excellent casing/cement bonding with the exception of two channels or microannuli in the middle and lower part of the section. No information on formation coupling.

The third comparison of results from various logging tools involves the occurrence of "fast formations," those formations that exhibit a travel time that is equal to or faster than the travel time for casing.

Figure A-7a is a section from a tool with a single transmitter/single receiver with three foot spacing. The VDL indicates what appears to be casing signals in the upper part of the section and formation signals in the lower part of the section. The VDL signal in the lower part is called formation signal because no chevrons are visible opposite the casing collars. The amplitude curve indicates some casing signals in three parts of the section.

Interpretation: Poor casing/cement bonding in the upper part. The amplitude curve and VDL are contradictory in the lower part of the section. The VDL indicates casing/cement bonding and the amplitude indicates poor bonding in one area.

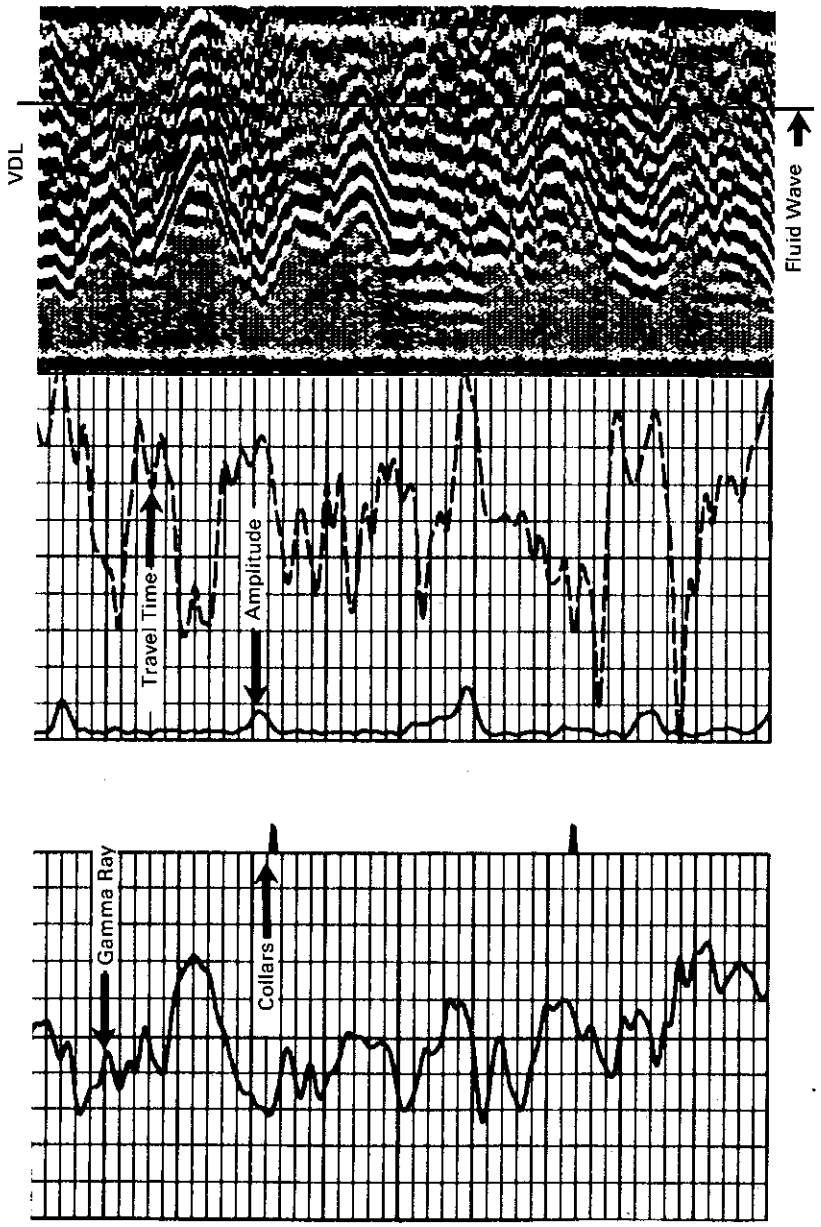



**Figure A-6c.** Single receiver 5-foot spacing.

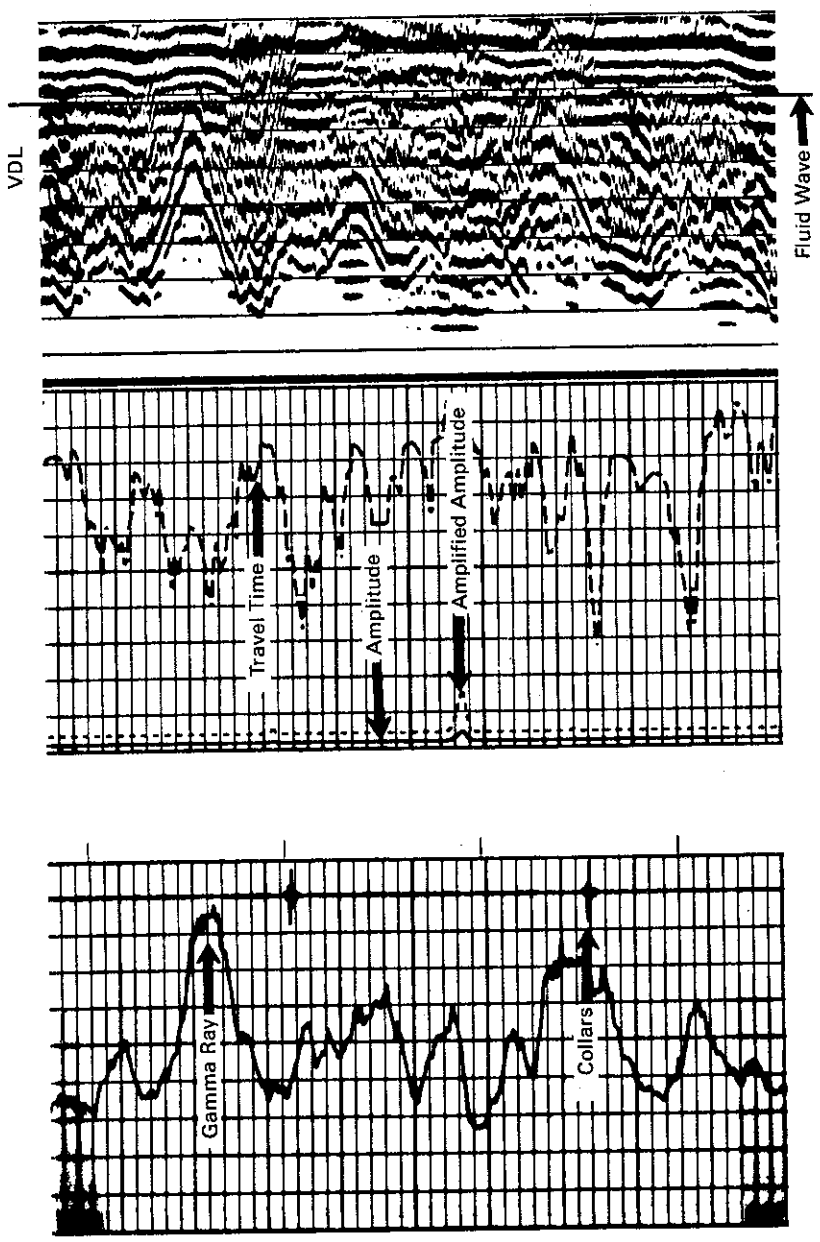



**Figure A-6d.** Dual receiver 3-foot/5-foot spacing.

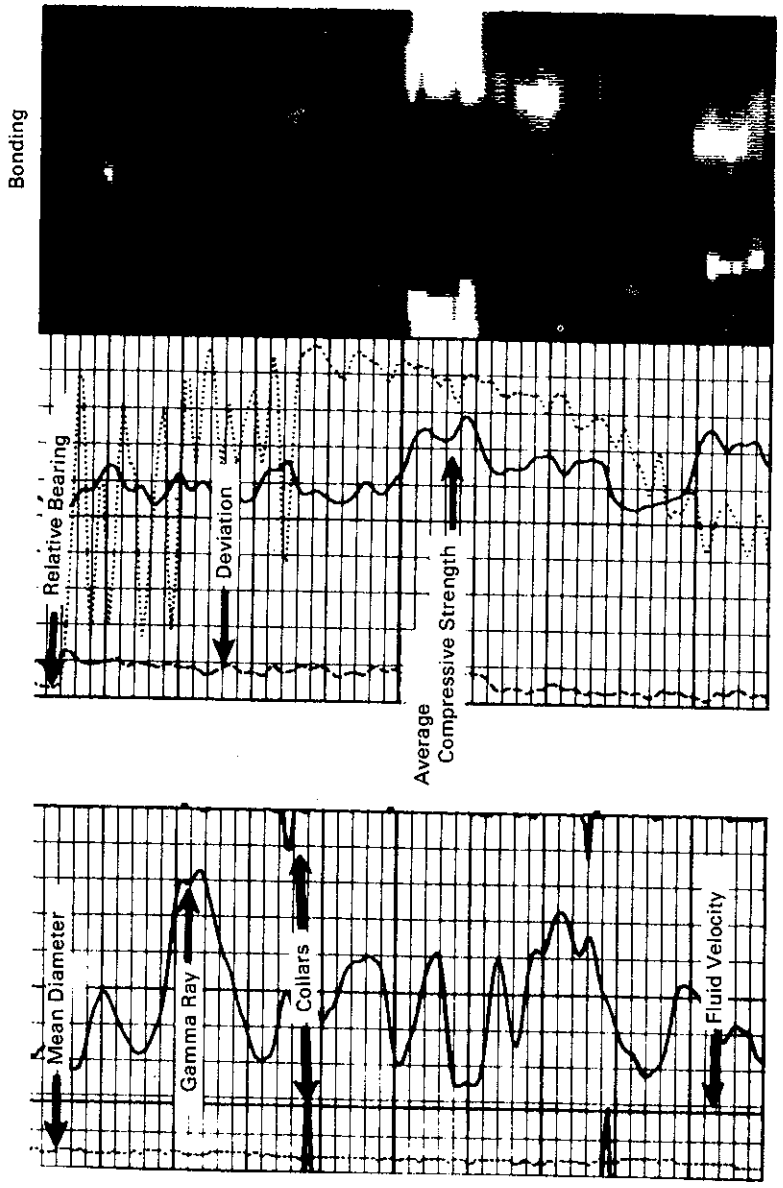



**Figure A-6e**. Second generation log - Company B.

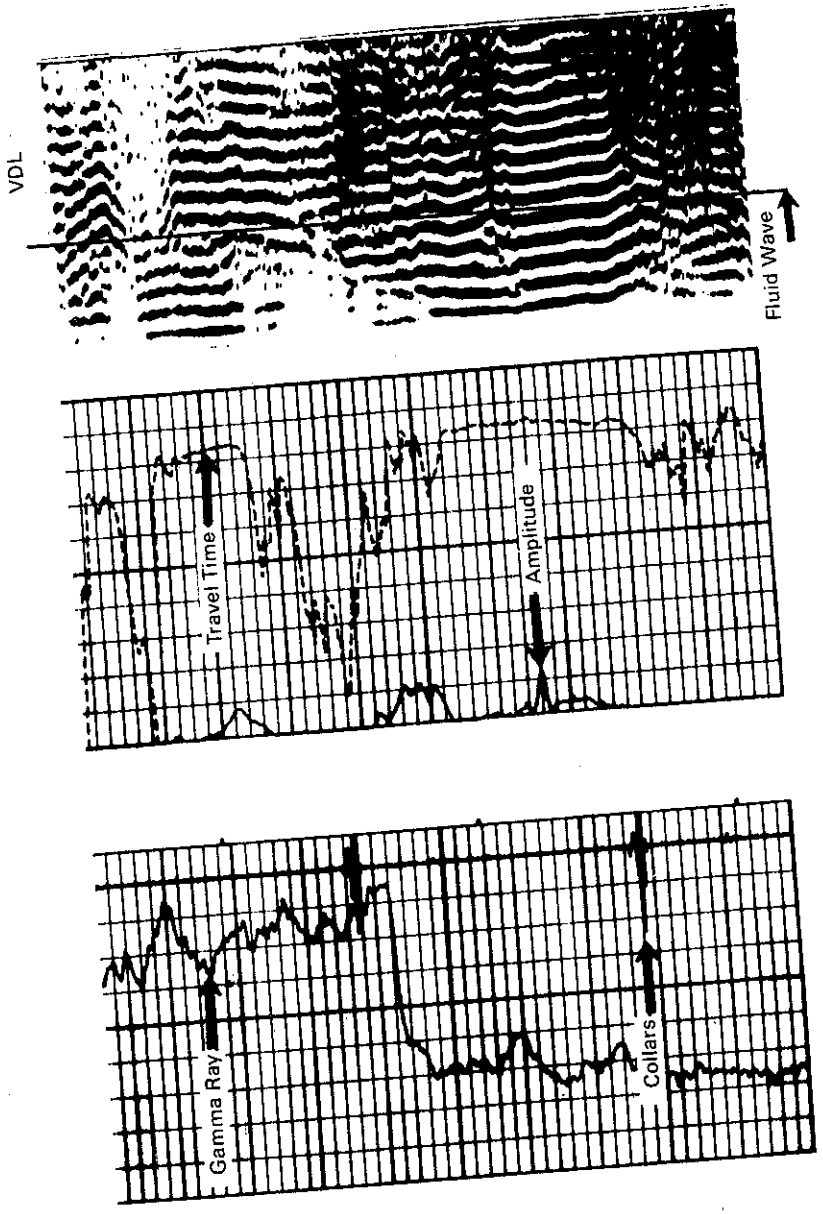



**Figure A-7a.** Single receiver 3-foot spacing.

Figure A-7b is a log of the same section with a tool with single transmitter/single receiver, four foot spacing. The VDL indicates casing/ cement bonding in most of the section with one area of formation signal in the lower part. The amplitude curve indicates casing signal in the lower part.

Interpretation: Good casing/cement bonding in the upper part of the section. No formation coupling in the upper part. The amplitude curve and VDL are contradictory in the lower part of the section.

Figure A-7c is a log of the same section from a tool with single transmitter/single receiver, five foot spacing. The VDL indicates formation signals throughout the section with possible casing signals in the upper part. The amplitude curve indicates poor casing/cement bonding throughout most of the section except for about 10 feet in the upper part and the lower 20 feet.

Interpretation: Poor cement/casing bonding throughout the section except for about 10 feet in the upper part and the lowermost 20 feet. The amplitude curve and VDL are contradictory in the lower part. The amplitude curve reads over 70mv, which indicates free pipe.

Figure A-7d indicates a log of the same section from a tool with single transmitter/dual receiver with three foot/five foot spacing. The VDL indicates formation signals throughout the section with casing signals in the upper part. The amplitude curve indicates cement/casing bonding with one possible problem in the upper part of the log.

Interpretation: Excellent cement/casing bonding throughout most of the section. Possible channels or microannuli in the upper part of the section. Formation coupling throughout most of the log.

Figure A-7e is the same section from one of the "second generation" logs. The bond image part of the log indicates three channels or microannuli in the upper two-thirds of the log. The minimum compressive strength curve supports that some problem exists in these areas.

Interpretation: Excellent cement/casing bonding with three channels or microannuli. No information on formation coupling.

As can be seen from these examples, casing signals and formation signals are very difficult to differentiate when a fast formation is involved.

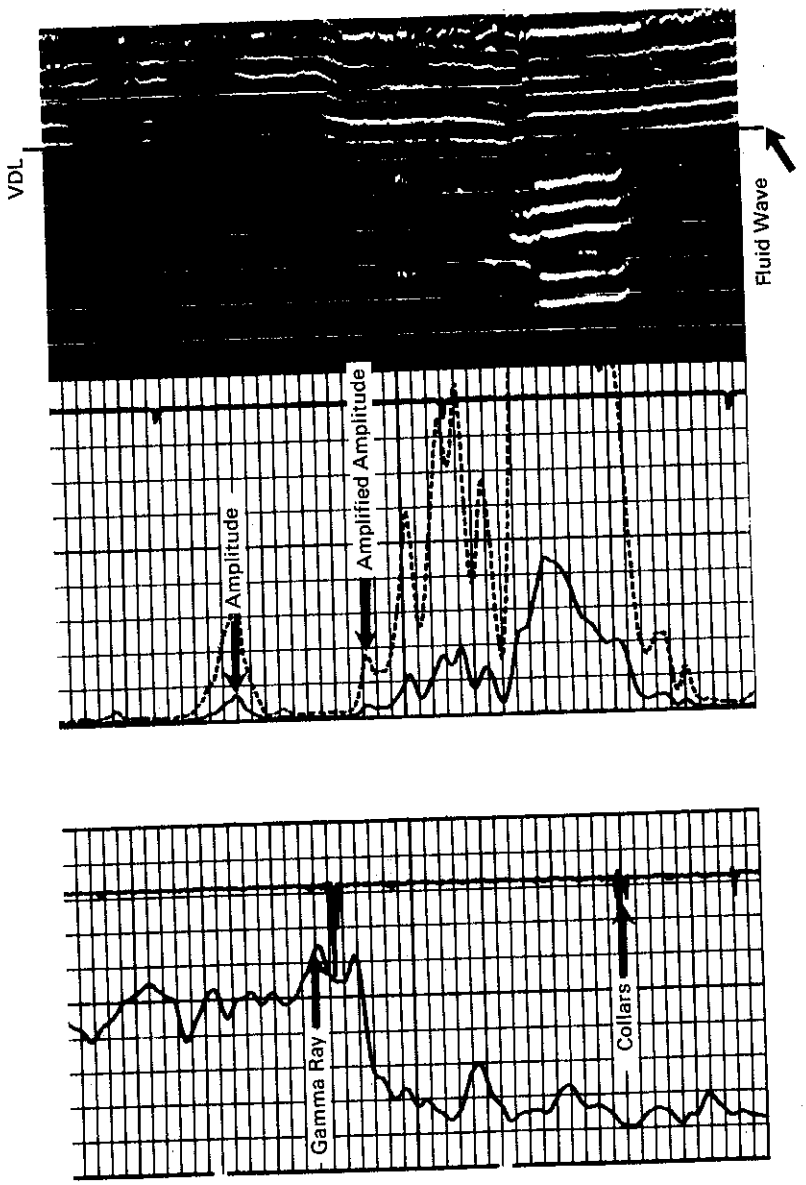



**Figure A-7b.** Single receiver 4-foot spacing.

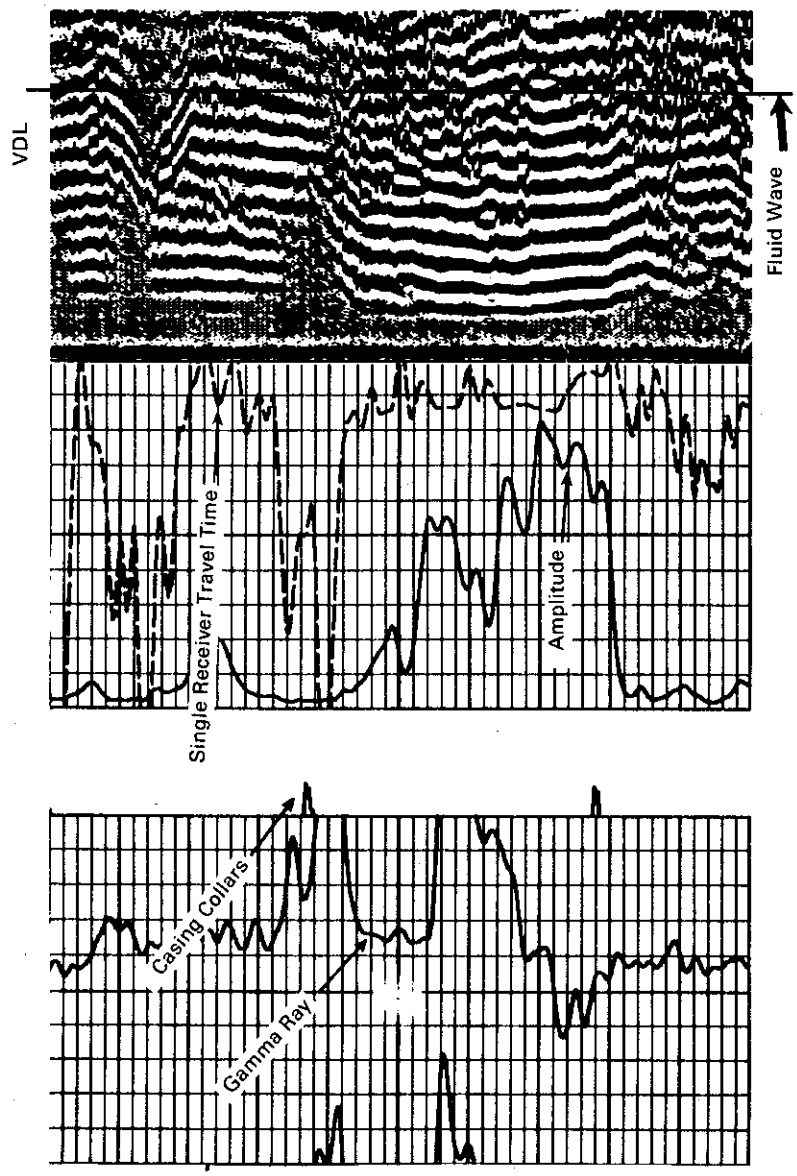



**Figure A-7c.** Single receiver 5-foot spacing.

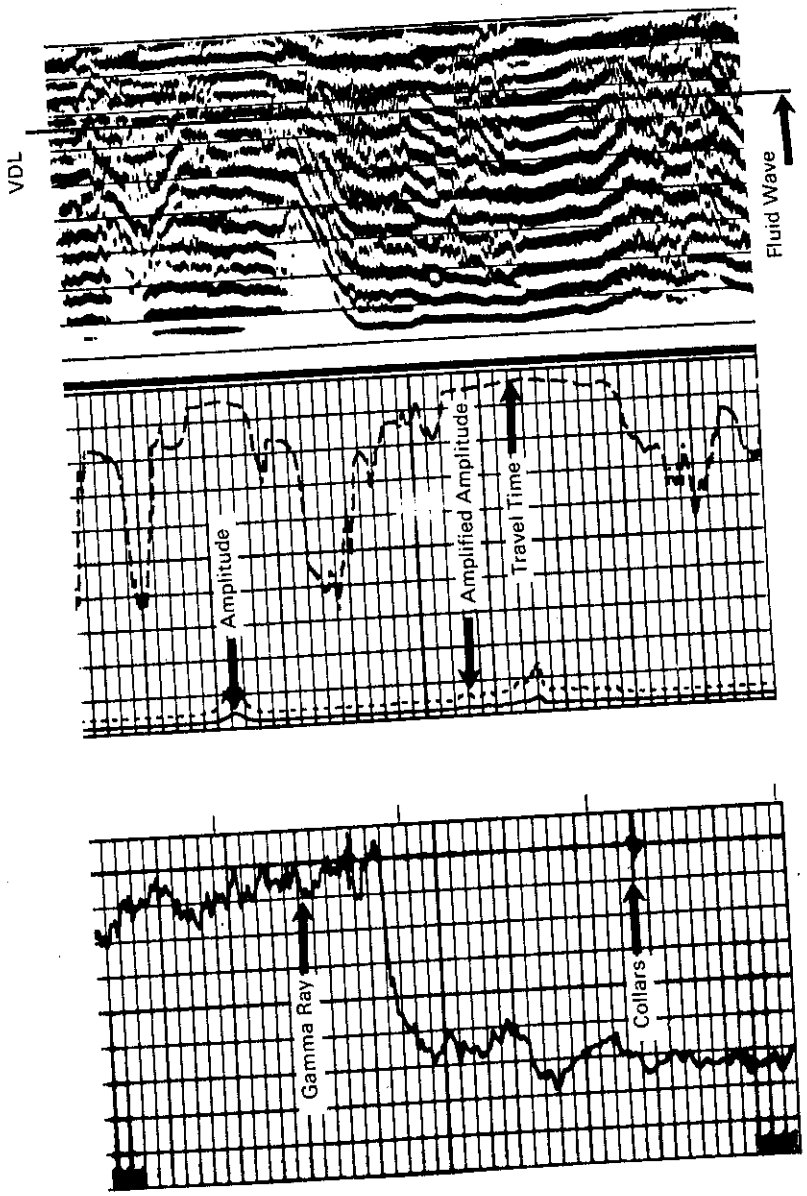



**Figure A-7d.** Dual receiver 3-foot/5-foot spacing.

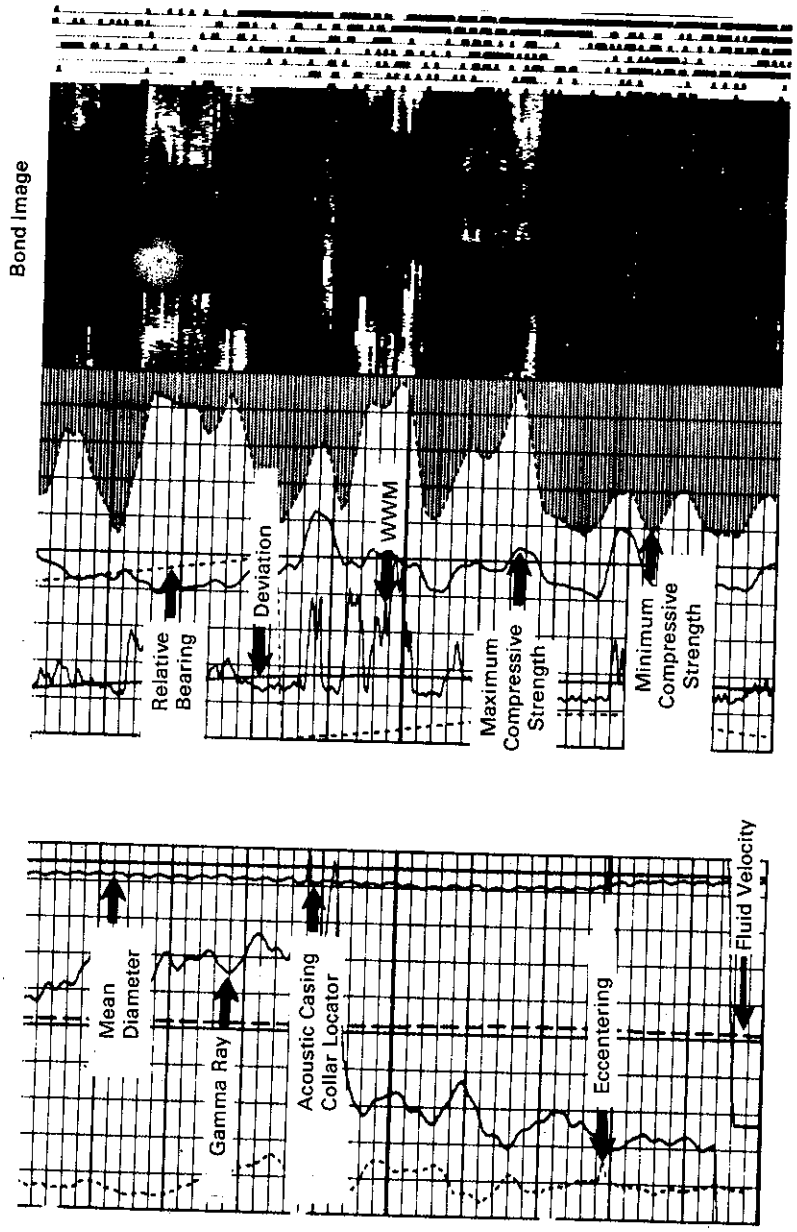



**Figure A-7e.** Second generation log - Company A.

# APPENDIX B

# LEAK TEST WELL DESIGN AND TESTING CRITERIA AND TEST SUMMARIES

## LEAK TEST WELL

The purpose of the "Leak Test Well" is to provide a facility to develop methods for testing the integrity of the tubing, casing and packer and for testing the capability of various down-hole tools to detect fluid movement behind the casing.

The design of the well generally corresponds to a typical salt water disposal well used in the oil and gas industry. That is, it includes the use of surface casing, long string, tubing, and packer. The deviation from the norm in this well includes two packers and a sliding sleeve on the injection tubing and a 2-3/8" tubing attached to the outside of the long string and running to the surface (Figure 9).

The depth to which surface casing was set was based on Oklahoma Corporation Commission regulatory requirements to extend below the occurrence of ground water having 10,000 mg/l or less total dissolved solids. The selection of the depth for locating the profile nipples and for the injection zone was based on porosity data from Compensated Density and Compensated Neutron logs from the "Logging Well."

The 2-3/8" tubing, outside the 5-1/2" long string, extends from a 1/4" hole in the long string at 1,070 feet below grade, to the surface of the ground. The hole was drilled using a 1/4" bit and a 2-3/8" elbow was welded to the casing so that the tubing could be attached. Profile nipples were placed in the tubing at 700 feet opposite the sand at 680-710 feet and at 920 feet opposite the sand at 905-935 feet . These nipples will control the leakage of fluid from the tubing in that fluid can exit the tubing at either of the nipples, or be brought to the surface.

Casing and equipment for the "Leak Test Well" include:

571 feet of 13-3/8" casing
1,215 feet of 5-1/2" long string
1,070 feet of 2-3/8" tubing outside the long string
1,120 feet of 2-3/8" tubing inside the long string
Baker Model "L" Sliding Sleeve
Baker Model "AD-1" Tension Packer
Baker Model "C-L" Tandem Tension Packer

Baker Model "R" Profile Nipple 1.78
Baker Model "RW Profile Nipple 1.81
Baker Model "F" Profile Nipple 1.87
Baker 5-1/2" Float Shoe
Hinderliter 10FSF Wellhead for dual completions (5-1/2" and 2 -3/8")
3 centralizers 5-1/2"

The surface equipment for the "Leak Test Well" consists of two 100-barrel fiberglass tanks, a 10-horsepower electric powered injection pump, high pressure injection flow lines, and schedule 40 plastic return flow lines (Figure 10). The water supply is from the City of Ada, Oklahoma. The control accessories are an air chamber, which smooths out the pumping actions of the pump pistons; a pressure control valve, which can be set to any predetermined pressure from 10 to 600 psi; a check value which prevents back flow in the injection line; a strainer to catch foreign material that may be pumped into the line; a flow meter to record the number of barrels of liquid pumped; a flow outlet pipe used to calibrate the flow meter; a control valve to regulate the flow to the injection well; a thermometer to determine the temperature of the injected fluids; and pressure gauges to indicate the injection pressure (Figure B-1).

Flow into the well can be controlled so that the injected fluids are directed into the 2-3/8" injection tubing, the tubing/casing annulus, or to the 2-3/8" outside tubing. Returned flows can be controlled from the 2-3/8" outside tubing and also from the annulus of the 5-1/2" casing.

Wells will be constructed to monitor each of the zones open to the "Leak Test Well." One well will be 700 feet deep, to monitor the sand at 680-710 feet; a second will be about 920 feet deep, to monitor the sand at 905-935 feet; and the third will be 1,130 feet deep, to monitor the pressures and water quality in the injection zone.

## TEST SUMMARIES

A number of specific tests are planned for the "Leak Test Well." As the tests are completed, brief summaries are prepared and forwarded to the Underground Injection Control Program Offices in EPA Headquarters and the regions. Summaries of those tests completed to date are presented in the remainder of this appendix.

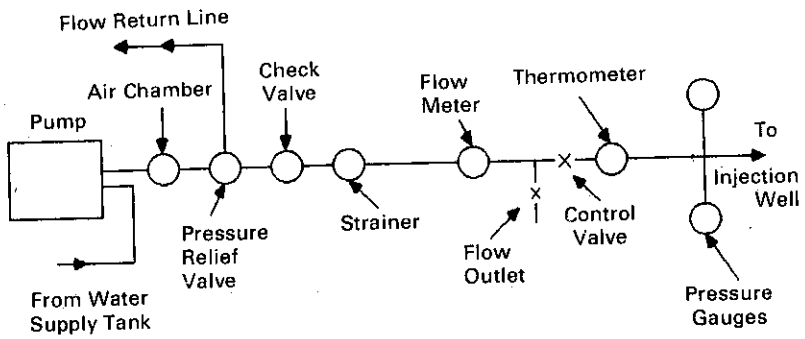



**Figure B-1.** Injection pump and control accessories.

## Test No. 1: Acoustic Cement Bond Tool Test for Flow Behind Casing

*Introduction*

In November 1986, personnel from Region IV and V witnessed a demonstration of the use of an acoustic cement bond tool for detecting fluid movement behind casing. The demonstration was conducted by Dresser Atlas personnel at their field office in Olney, Illinois, and involved pumping water through the annular space between two concentric pieces of pipe while holding the bond tool stationary in the inner pipe.

EPA personnel suggested that the tool(s) be tested in the "Leak Test Well" at the Robert S. Kerr Environmental Research Laboratory to get a better definition of the sensitivity of the tool and the conditions under which it will or will not work.

C.D. "Mac"McGregor, a log analyst for Dresser Atlas, contacted Kerr Lab personnel and plans were made to run the tests on January 23, 24, and 25, 1986.

*Test Well Conditions*

The purpose of the test was to determine if flow of water at various rates could be detected behind pipe using the data presented by the fluid wave from a cement bond tool. The test was developed in two phases, phase I looking at flow immediately behind casing under free pipe conditions, and phase II looking at flow in tubing behind casing under conditions which would possible simulate flow in a channel in cement.

Figure B-2 indicates the configuration of the Leak Test Well for the initial test. In this configuration, water was pumped down the tubing/casing annulus into the injection zone. This represents flow in the free-pipe condition, i.e., no cement behind the pipe (2-3/8" tubing in this case).

Figure B-3 indicates the well configuration for the second test, which was designed to simulate flow in a channel in cement. The section of the well between 1,070 and 950 feet has cement behind the 5-1/2" casing and thus around the 2-3/8" tubing. Thus the tubing in that area represents, to some degree, a channel in the cement. In this phase, water was pumped down the 2-3/8" tubing, into the 5-1/2" casing and out the perforations.

*Test - Phase I*

The test was conducted with a 1-11/16" OD Acoustic Cement Bond Tool with a single transmitter/single receiver with four foot spacing. The tool was placed in the injection tubing at 57 feet and the oscilloscope was viewed in the no-flow and flow conditions.

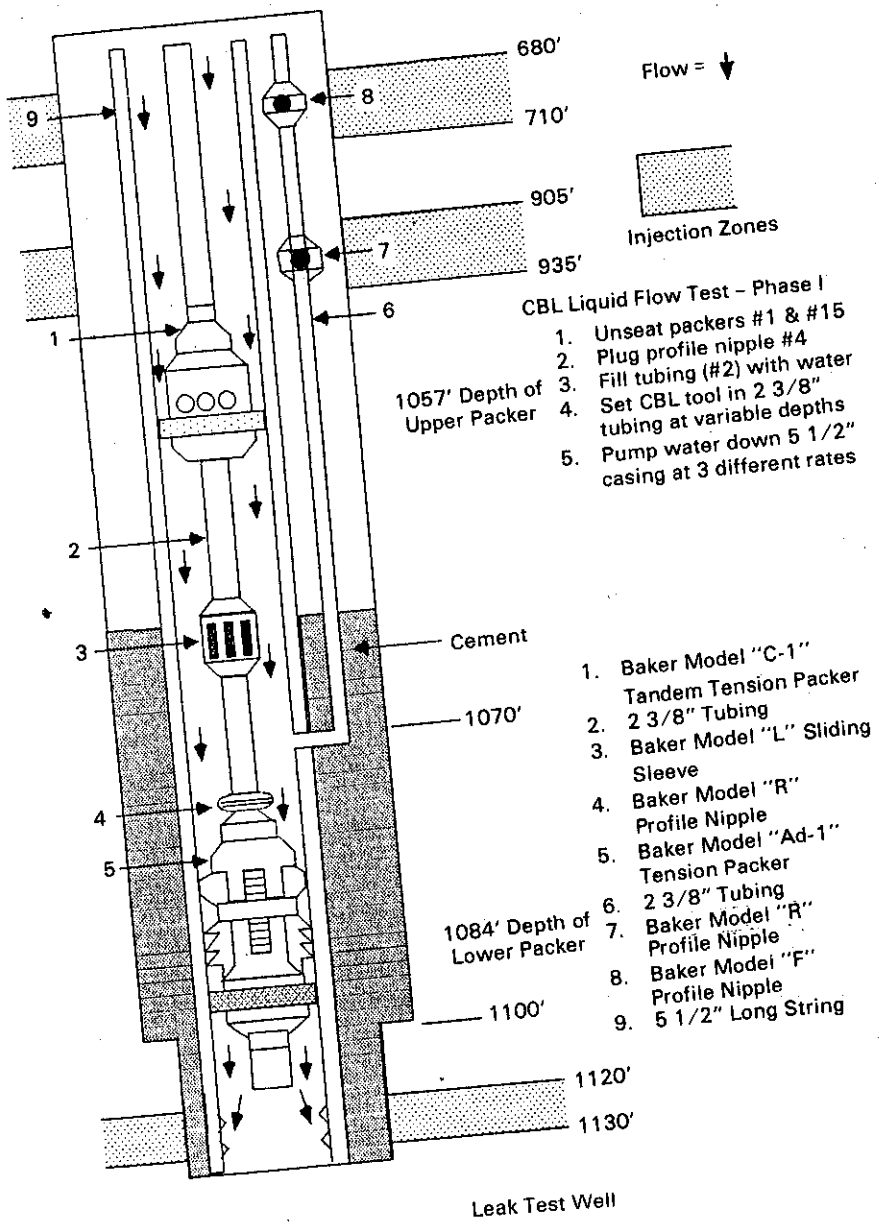



**Figure B-2.** CBL liquid flow test - Phase I.

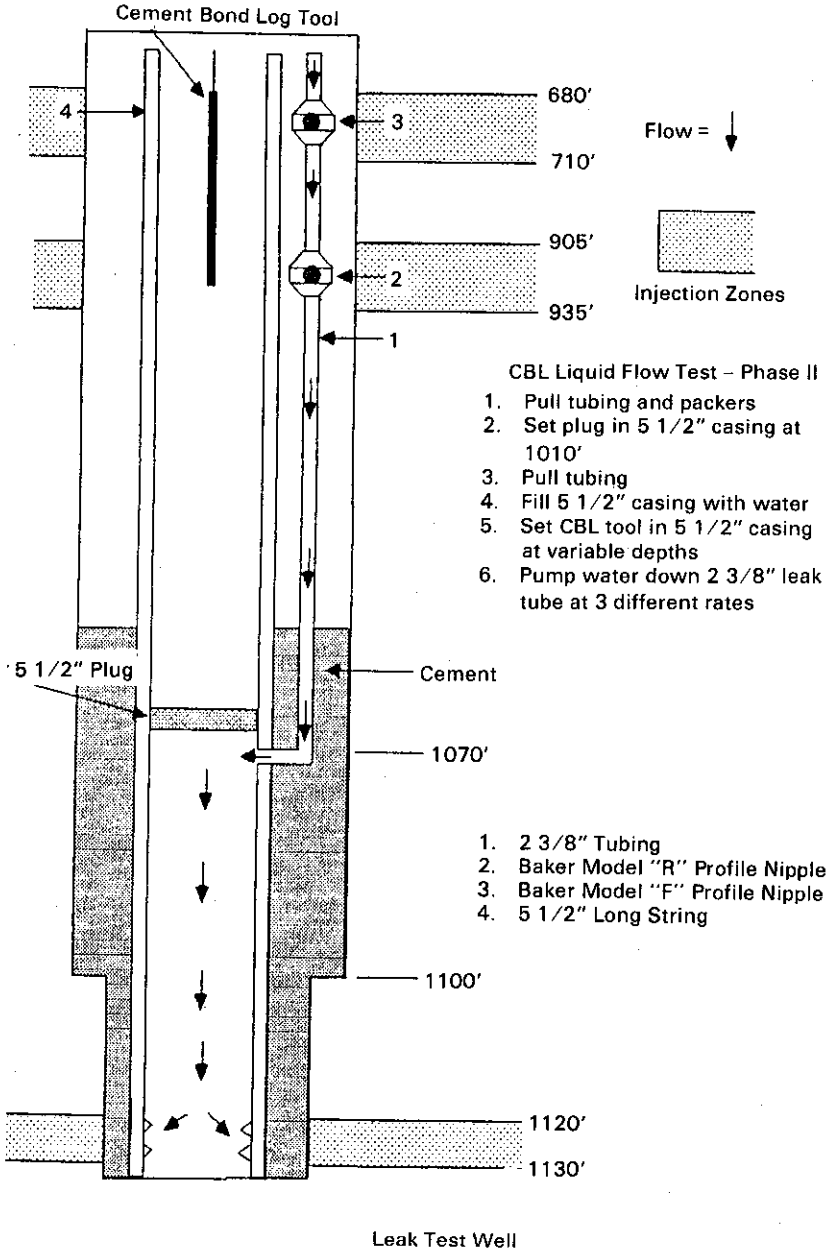



**Figure B-3.** CBL liquid flow test - Phase II.

Test - Phase I

| Time | Flow Rate | Oscilloscope Response |
|---|---|---|
| 1:50 p.m. | No flow | None |
| 2:00 p.m. | 8 gpm | Yes |
| 2:03 p.m. | 4 gpm | Yes |
| 2:17 p.m. | 0.78 gpm | Yes |
| 2:20 p.m. | 0.78 gpm + air | Yes |
| 2:24 p.m. | 6 gpm + air | Yes |
| 2:30 p.m. | Stopped injection | Yes |

The test was repeated with the tool at various depths in the well, with the same results, that is, the oscilloscope indicated no distortion of the fluid wave int he no-flow condition and distortion at all three flow rates. The distortion was greater when air was added to simulate gas movement behind the pipe.

*Test - Phase II*

The second test was conducted with the tubing and packers removed and a bridge plug set as indicated by the Phase II diagram. The Acoustic Cement Bond Tool used for this test was a 3-5/8" OD tool with single transmitter/single received with five foot spacing.

Test - Phase II

| Tool Depth feet | Flow Rate gpm | Oscilloscope Response |
|---|---|---|
| 600 | 8 | None |
| 700 | 8 | None |
| 800 | 8 | None |
| 900 | 8 | None |
| 1000 | 8 | None |

The tool was initially set immediately above the bridge plug and the oscilloscope viewed in the no-flow condition. Water was then pumped down the outside tubing at a rate of 8 gpm. No distortion of the fluid wave was evident on the oscilloscope. The tool was then moved up the hole in 100 foot increments. No distortion of the fluid wave was evident at any depth, thus no flow was detected in the tubing.

*Conclusions*

The Phase I test results indicate that the fluid wave of the Acoustic Cement Bond Tool responded to fluid movement behind the tubing in a free-pipe condition, that is with no cement behind the pipe. A response was evident with flow as low as 0.78 gpm.

The tool used in the Phase II test did not pick up flow in the 2-3/8" tubing either within or above the cemented section of the well.

Thus, flow in the manmade channel behind the 5-1/2" casing could not be detected under the test conditions.

One explanation for the responses observed under the test conditions previously outlined is that under free pipe conditions, the paths for movement of the sound wave are through the casing and fluid. Thus, under static conditions where the tool is not moving and there is no movement of fluid in or behind the pipe, the fluid wave, as presented on the oscilloscope, is also static. On the other hand, flow of fluid behind the pipe while the tool is stationary affects the sound wave as it moves through the fluid, causing a distortion of the wave. This distortion shows up as rapid changes in amplitude in the display of the fluid wave on the oscilloscope and indicates movement of the fluid. Thus, under free pipe conditions, the fluid wave has the capacity to reflect fluid movement behind pipe.

The presence of cement behind pipe presents a much more difficult set of conditions for identifying fluid movement with the cement bond tool. The paths for the sound wave under these conditions are: movement along the casing and cement (small signal because of the attenuation effect of the cement behind the casing), movement through the formation and movement through the fluid. The heterogeneity of the formation, the size of the channel, and type and amound of fluid movement will all affect the ability of the tool to identify fluid flow in channels in cement. Thus, the capability of the acoustic cement bond tool to identify fluid flow in channels is unproven, though certainly not impossible.

*Recommendations*

Field data should be accumulated to determine the capability of this type of tool for detecting flow behind casing in varying well conditions; i.e. free pipe and channels in cement.

When running other tools, such as temperature or noise surveys for detecting flow behind pipe, service companies should run the bond tool for comparison purposes to determine if flow in channels can be detected.

## Test No. 2: Nuclear Activation Technique for Detecting Flow Behind Casing

*Introduction*

On January 23 and 24, 1987, personnel from the Robert S. Kerr Environmental Research Laboratory (RSKERL) and Dresser Atlas conducted a series of tests for determining flow behind pipe using two neutron activation tools.

The purpose of the tests was to determine if flow of water at various rates could be detected behind the pipe using the data presented by a pulsed neutron lifetime logging system (PDK-100), and a Cyclic Activation Tool.

*Tools Tested*

Two tools were tested during the two-day period:

- a 1-11/16" diameter PDK-100 Tool
- a 3-5/8" diameter Cyclic Activation Tool

The operation of both tools is based on a nuclear activation technique in which flowing water is irradiated with neutrons emitted by a logging sonde. These neutrons interact with oxygen nuclei in the water to product nitrogen -16. $^{16}N$ decays with a half-life of 7.13 seconds, emitting gamma radiation. The flow is then computed from the energy and intensity response of two gamma ray detectors mounted in the logging sonde.

*Test Well Conditions*

The tests were developed in four phases, the first three using the PDK-100 Tool and the last using the Cyclic Activation Tool.

Figure B-4 indicates the configuration of the Leak Test Well for the initial test. In this configuration, water was pumped down the tubing/casing annulus into the injection zone with the 1-11/16" diameter PDK - 100 Tool held stationary in the 2-3/8" injection tubing. This condition represented flow in the free-pipe condition, i.e., with no cement behind the pipe (2-3/8" tubing in this case). A valve at the surface on the outside 2-3/8" tubing was closed so that circulation was not possible up that tubing.

Figure B-5 indicates the well configuration for the second test, which was designed to simulate upward flow in a channel in cement. Water, pumped down the tubing/casing annulus moves through a 1/4" hole in the 5-1/2" casing at 1,070 feet and up the 2-3/8" outside tubing. The section of the wall between 1,070 and 950 feet has cement behind the 5-1/2" casing and thus around the 2-3/8" tubing. The tubing in that area represents, to some degree, a channel in the cement.

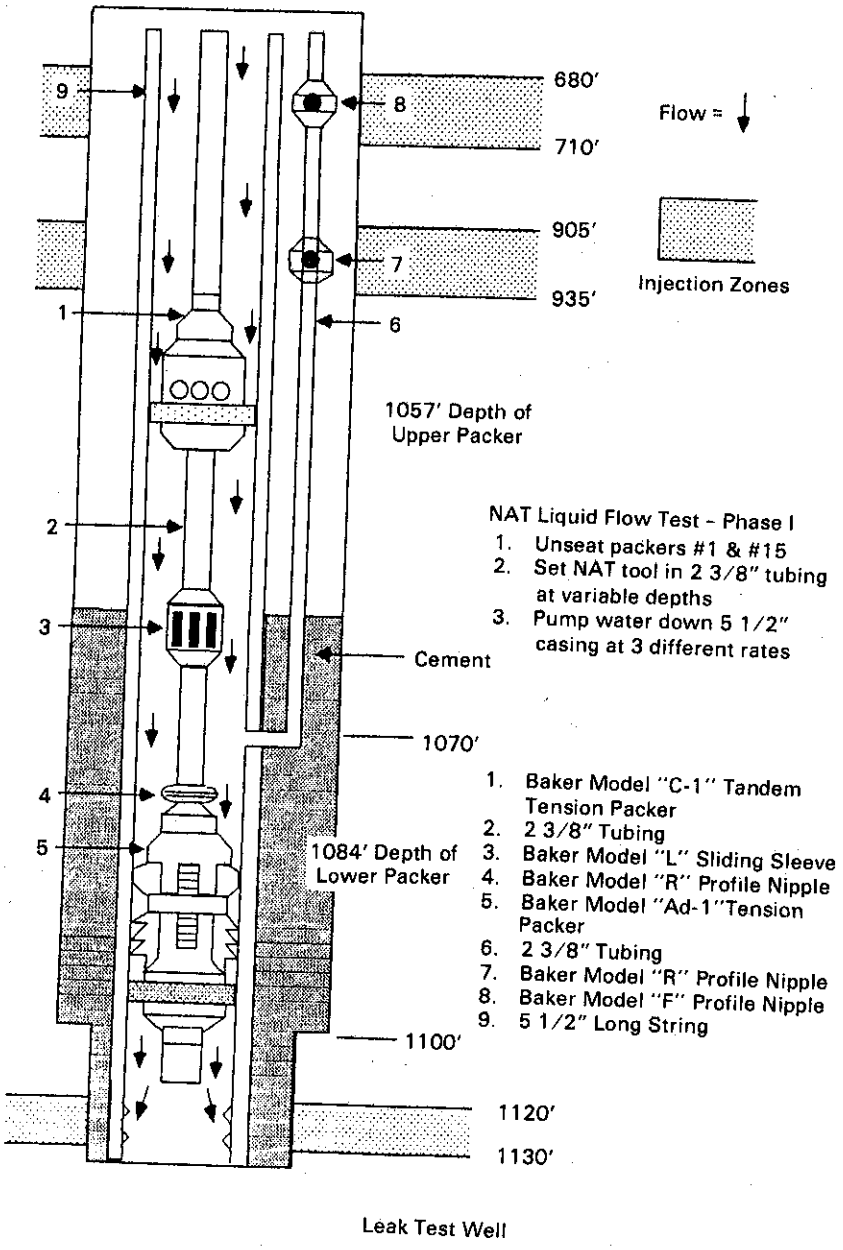



**Figure B-4.** Neutron activation tool liquid flow test - Phase I.

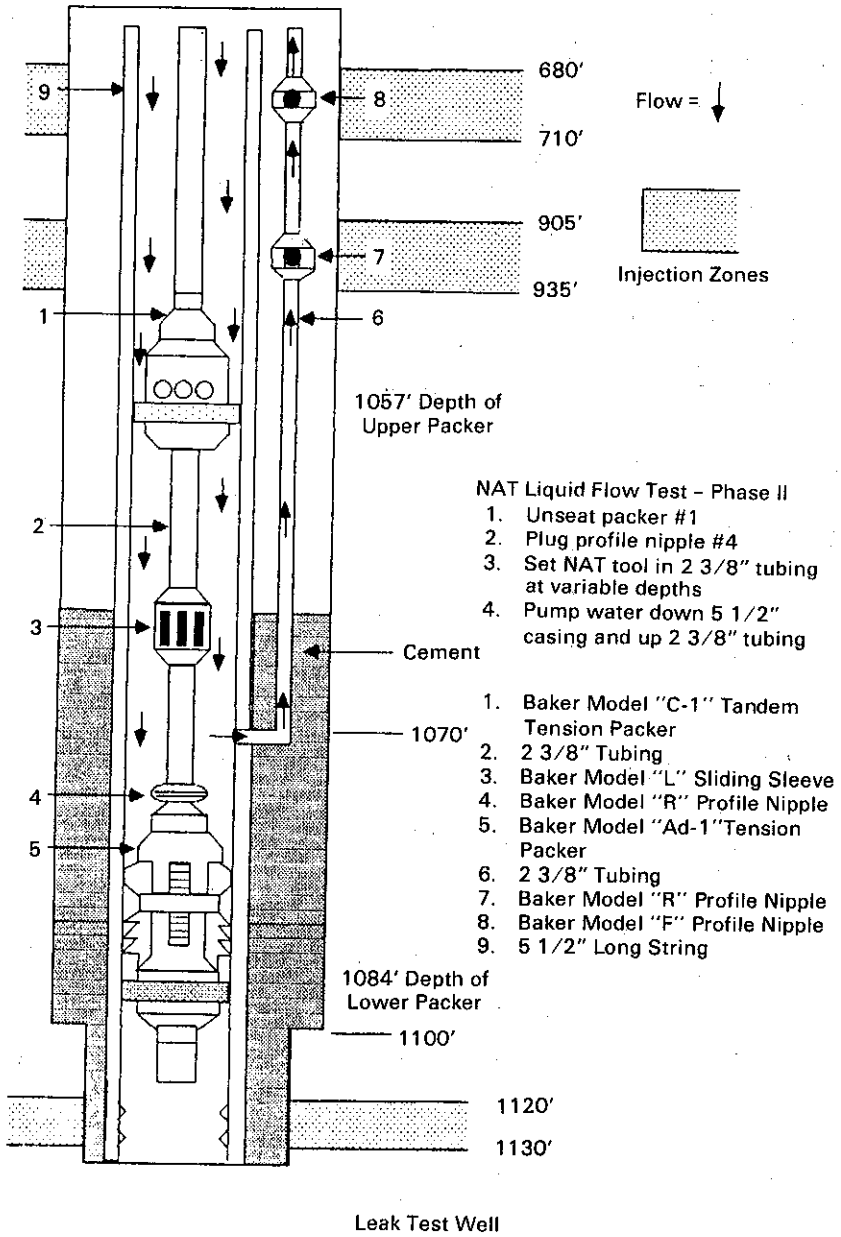



**Figure B-5.** Neutron activation tool liquid flow test - Phase II.

Figure B-6 indicates the well configuration for the thrid test, which was designed to simulate downward flow in a channel in cement. Water, pumped down the 2-3/8" outside tubing moves through the 1/4" hole in the 5-1/2" casing at 1,070 feet and up the 5- 1/2" asing to the surface.

Figure B-7 indicates the well configuration for the final test, which was designed to simulate downward flow in a channel in cement using the larger Cyclic Activation Tool. Water, pumped down the 2-3/8" outside tubing, flows into the 5-1/2" casing through the 1/4" hole and out through perforations into the injection interval from 1,120 to 1,130 feet.

*Test - Phase I*

This test was conducted with the PDK-100 Tool with the two detectors located below the neutron generator so that downward flow could be detected. With the tool located at 300 feet inside the 2-3/8" injection tubing, data was obtained under conditions of no flow and flow of 8, 4 and 1 gallon per minute (gpm). Two replications of these flow rates were conducted and flow was detected by the tool in all instances.

*Test - Phase II*

This test was conducted with the PDK-100 Tool with the two detectors located above the neutron generator to determine if flow up the outside 2-3/8 could be detected. With the tool located at 600 feet, data was obtained under no flow, and 8 gpm flow conditions. Flow up the outside 2-3/8" tubing could not be detected.

*Test - Phase III*

This test was conducted with the PDK-100 Tool at 600 feet with the generator-detector configuration identical to the Phase II test. Water was pumped down the 2-3/8" outside tubing and up the 5-1/2" casing at three different rates (8,4, and 1 gpm). Upward flow was detected in the 5-1/2" casing at all three flow rates.

The tool configuration was then changed with the detectors below the generator to determine if downward flow in the outside tubing could be detected. Flow down the outside 2-3/8" tubing could not be detected.

*Test - Phase IV*

This test was conducted using a 3-5/8" diameter Cyclic Activation Tool. The detectors were located below the generator for detecting flow in the 2-3/8" tubing as water moved down the tubing, through the 1/4" hole into the 5-1/2" casing and out the perforations into the injection interval. Flow rates for this test were 7.8, 6.1 and

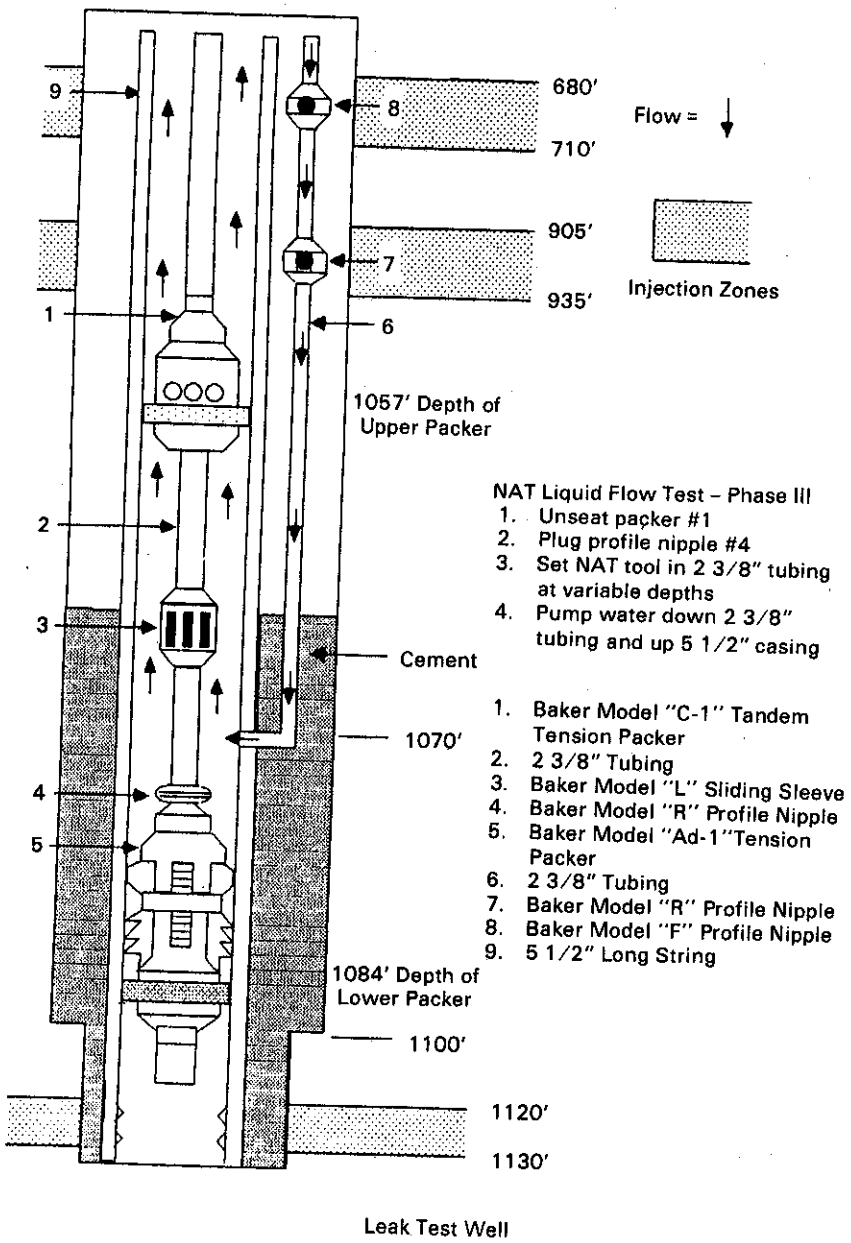



**Figure B-6.** Neutron activation tool liquid flow test - Phase III.

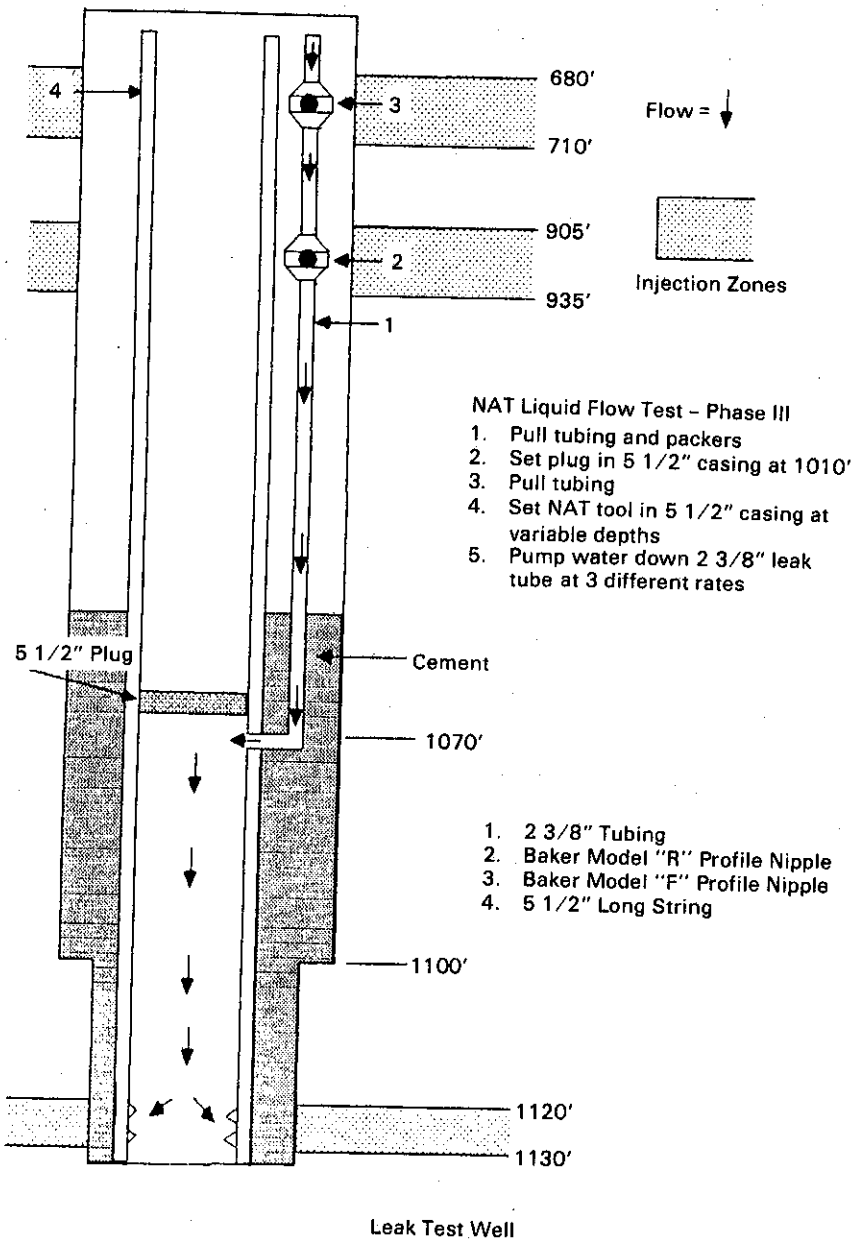



**Figure B-7.** Neutron activation tool liquid flow test - Phase IV.

0.79 gpm. All three flow rates were detected by the tool and flow velocities were calculated from the data collected by the tool.

*Conclusions*

The PDK-100 Tool was able to detect all three flow rates when flow was up or down the 5-1/2" casing. The tool did not detect any flow up or down the outside 2-3/8" tubing.

The Cyclic Activation Tool was able to detect all three flow rates in the outside 2-3/8" tubing. In addition, the computer associated with the tool has the capability to compute a velocity of flow for each flow rate.

*Recommendations*

Additional work should be done to increase the sensitivity of the PDK-100 Tool. It should be noted here that since the tests were conducted, Dresser Atlas personnel have made some modifications to the PDK-100 Tool and have been able to detect flow in outside tubing in a well constructed very similarly to the Leak Test Well. The adjusted tool will be retested at the RSKERL Test Facility as soon as it can be arranged. In the meantime, Dresser Atlas personnel will run the tool in several wells owned by Mobil, and will make that results available to RSKERL personnel.

The Cyclic Activation Tool should be tested under "real well" conditions to verify the results seen during the tests on the Leak Test Well.

The capability of this equipment to locate flow behind pipe could be a significant breakthrough for mechanical integrity testing. Especially the PDK-100 Tool which can be run in tubing filled with water or with only air present. Thus, no workover costs would be involved in testing a well, i.e. setting plugs, pulling tubing, etc.

## Test No. 3: Testing for a Hole in the Long String

*Introduction*

On January 23, 24 and 25, 1987, while testing tools for detecting flow behind casing, test results indicated a possible hole in the 5-1/2" long string of the research well. A series of tests was conducted on the well on January 25, 27, February 2, 3, 10, 11 and 12 to determine whether or not there was a hole in the pipe.

*Test Well Conditions*

The attached diagram (Figure B-8) indicates the well configuration during most of the tests to be discussed. Any changes in the well will be noted as the various tests are discussed.

While testing an Acoustic Cement Bond Tool (ACBT), the 5-1/2" casing was full of fluid above a bridge plug and water was being pumped down the outside 2-3/8" tubing at about eight gpm. Pumping had been in progress only about 5 minutes when water began flowing out of the 5-1/2" casing at about 2 1/2 gpm.

The immediate thought was the bridge plug was leaking, however, the Baker Packer representative was confident that the bridge plug could not leak. In checking the setting depth for the plug it appeared possible that it was located opposite a casing collar. The plug was reset to insure that it was properly set between collars.

*Acoustic Cement Bond Tool*

A plan was developed to systematically check the well to determine where the leak was in the system. The first approach was to use the ACBT to determine if flow in the 5-1/2" casing was occuring. The tool was set immediately above the bridge plug, which was set at 1,010 feet, and readings were taken to determine if flow would be reflected by the fluid wave. The tool was then moved up the well at 100 foot increments and readings taken, with the following results:

| Depth feet | Flow Indicated |
|---|---|
| 1,000 | No |
| 900 | No |
| 800 | No |
| 700 | No |
| 600 | No |
| 500 | No |
| 400 | No |
| 300 | Yes |
| 250 | Yes |
| 200 | Yes |

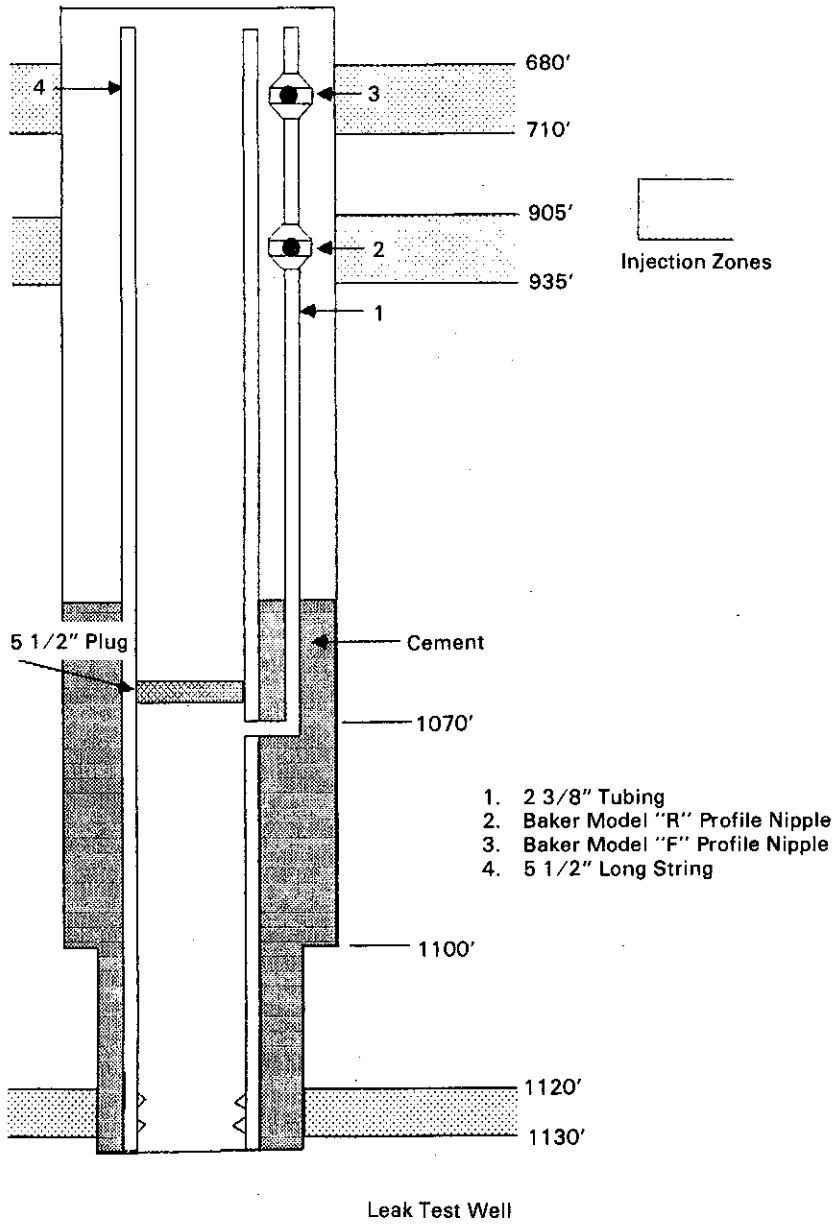



**Figure B-8.** Testing for a hole in the long string.

The tests were rerun with the same results. Thus, the ACBT data indicated that flow might be coming into the casing around 300 feet.

*Down Hole TV*

On January 27, 1987 Layne-Western Company brought their down- shot camera to survey the well to locate any hole that might be present. The regular lens would not give a good image, so a lens that must be used in air rather than water was tried. First the well was swabbed so that the water level was about 870 feet below land surface.

The camera, which had never been run in 5-1/2" casing, provided an excellent picture of the casing as it was lowered down the casing. An anomaly was seen at about 240 feet that could possibly be a damaged area of the casing.

*Pressure Test - Gas*

The next test was to pressure the well with nitrogen and shut it in to determine if any loss of pressure would occur over time. The well with the bridge plug still intact at 1,010 feet, was pressured to 185 psi with nitrogen and shut in. There was no loss of pressure evident after one hour.

*Pressure Test - Water*

The gas pressure was relieved and the injection pump hooked up to fill the 5-1/2" casing with water. After filling, 150 psi pressure was added to the weight of the water column and the well was shut in for one hour. No pressure drop was noted.

Pressure was relieved and water was pumped down the outside 2-3/8" tubing at about 8 gpm. After pumping for only 5 minutes, water began flowing out of the 5-1/2" casing at a rate of about 2 1/2 gpm.

*Pressure Test - Packer*

Next, Baker Packer, using a full-bore packer on tubing performed a series of pressure tests with the packer set at various depths in the casing, as follows:

| Packer Depth feet | Pressure psi | Drop in Pressure after 5 minutes |
|---|---|---|
| 115 | 92 | None |
| 295 | 115 | None |
| 595 | 100 | None |

*Ada Pressure Test*

The final test was a modified "Ada Pressure Test". After removing the bridge plug, nitrogen was used to move the static water level toward the hole in the 5-1/2" casing. A pressure of 380 psi was placed on the fluid in the casing and held overnight with no loss of pressure.

*Conclusions*

The series of pressure tests performed on the well clearly indicated that no hole is present in the 5-1/2" casing. The differential pressure bridge plug apparently did not have sufficient pressure differential to set securely, thus allowing the plug to leak when injection was taking place down the outside tubing.

The ACBT and down-hole TV were inconclusive in that a doubt still existed after reviewing data from the tests.

## Test No. 5: Nuclear Activation Technique for Detecting Flow Behind Casing

*Introduction*

On April 8, 1987, personnel from the Robert S. Kerr Environmental Research Laboratory (RSKERL) and Dresser Atlas conducted a series of tests to determine flow behind pipe using the PDK-100 Flow Tool.

Purpose of the tests was to determine if flow of water at various rates could be detected behind pipe from data presented by a pulsed neutron lifetime logging system (PDK-100). The 1-11/16" diameter tool had been tested on January 23 and 24, 1987, and could detect flow immediately behind the injection tubing but could not detect flow in the outside 2-3/8" tubing. The tool has been modified for the new series of tests.

*Test Well Configuration*

Figure B-9 indicates the configuration of the Leak Test well for the test. Both packers were set, the sliding sleeve was open and injection was maintained down the outside tubing at varying injection rates.

*Tool Testing*

For each flow rate the PDK-100 was held stationary at a depth of 300 feet in the injection tubing. After taking two background checks, flow was initiated down the outside tubing at a rate of 8, 6, 4, 2, and 0.105 gpm. The results of the tests for detecting flow:

| Flow Rate gpm | Flow Detected |
|---|---|
| 8 | Yes |
| 6 | Yes |
| 4 | Yes |
| 2 | Yes |
| 0.105 | No |

Readings were taken three (3) times at each flow rate.

*Conclusion*

The PDK-100 was able to detect four of the five flow rates with no problem. Movement was detected for the 0.105 gpm flow but it was probably the column of water in the tubing moving toward static conditions since at this extremely low flow the fluid level in the tubing could not be maintained.

The capacity of this tool to locate flow behind casing looks very promising. The next phase should be field testing under "real well" conditions.

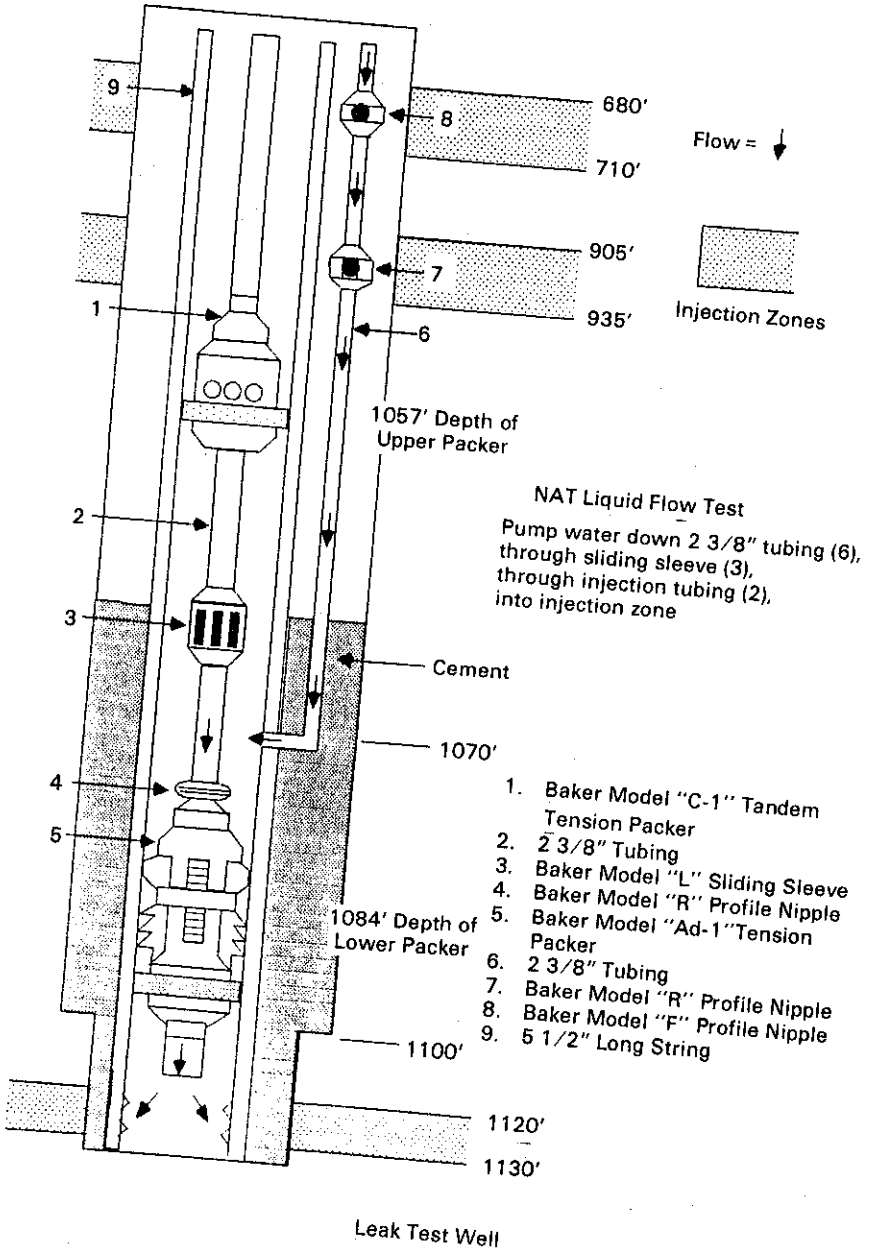



**Figure B-9.** Neutron activation tool liquid flow test.

## Test No. 6: Radial Differential Temperature Survey

*Introduction*

On April 27, 1987, Gearhart Industries, Inc., was contracted to run a Radial Temperature Survey on the "Leak Test" Well to determine the capability of this tool to detect vertical flow behind casing.

The Radial Differential Temperature (RDT) tool employs two highly sensitive temperature probes which extend from the centralized 1-11/16" O.D. housing to contact the casing. As these probes are rotated, they measure any difference in temperature at two points on the casing 180 degrees apart.

*Well Configuration*

Figure B-10 indicates the Leak Test Well configuration for the RDT survey. The fluid level in both the 5-1/2" casing and the 2-3/8" tubing was 190 feet below the surface of the ground.

*Radial Differential Temperature Survey*

The procedure for running the RDT in the Leak Test Well was to run a conventional temperature profile, take RDT readings at five (5) depths under no-flow conditions, then repeat the RDT readings at the five depths after beginning injection down the outside 2-3/8" tubing.

The temperature profile indicated that the fluid level in the 5-1/2" casing was at 190 feet below land surface. RDT scans at 1,050, 1,025, 1,000, 975, and 850 feet, under no-flow conditions, showed the same temperature for both probes as they were rotated at each depth. (See Figure B-11).

Injection down the outside 2-3/8" tubing was started at 10:57 a.m., and the RDT surveys at 11:05 a.m. The scan at 975 feet began to show a temperature difference as a result of the injection down the tubing. The temperature differential is easily seen at 1,025 feet (Figure B-12).

A final scan at 850 feet indicated the temperature variation one would expect with cooler fluid flowing in a channel outside the long string.

*Conclusion*

The Radial Differential Temperature tool easily identified cooler water flowing in the outside tubing in the Leak Test Well.

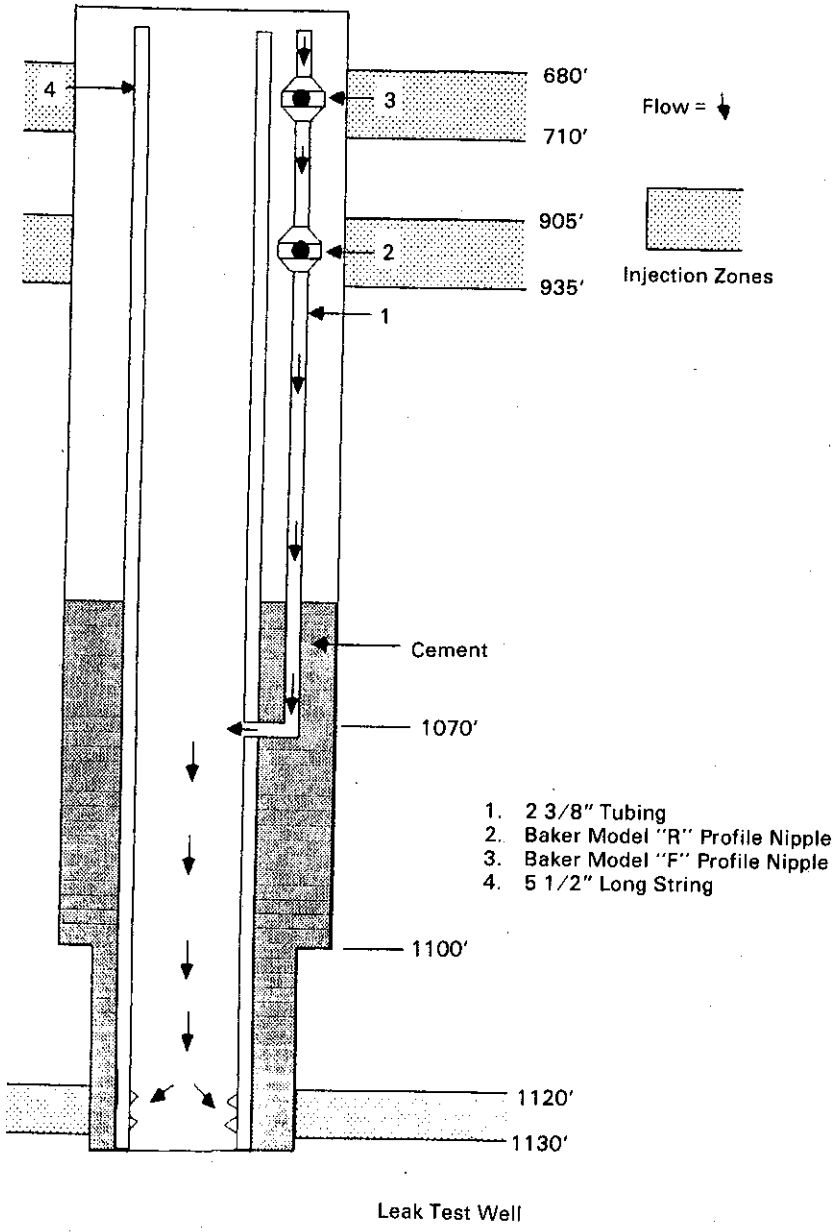



**Figure B-10.** Radial differential temperature survey.

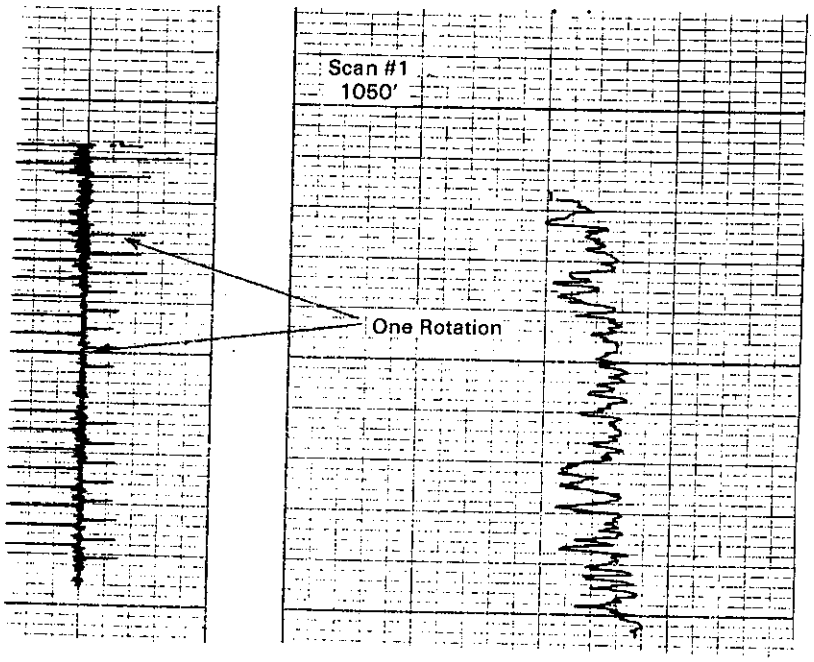



**Figure B-11.** RDT scan no-flow condition.

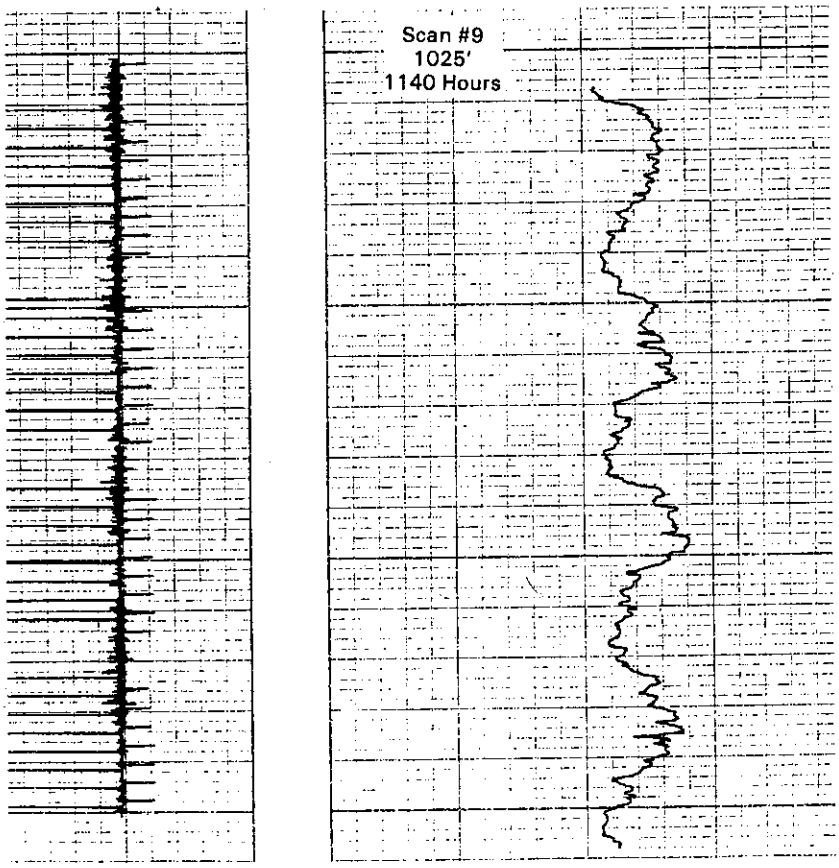



**Figure B-12.** RDT scan flow condition.

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