MECHANICAL INTEGRITY TESTING (MIT)

EPA Region 6

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(Credits to George Robin, Steve Platt & Chuck Tinsley)

What we protect:

USDWs

(Underground Sources of Drinking Water)

Pronounced:

you wess dee dubyas

Mechanical Integrity (MI)

Part 1

Internal Mechanical Integrity

40 CFR §146.8(a)(1)

Part 2

External Mechanical Integrity

40 CFR §146.8(a)(2)

146.8 Mechanical integrity.

(a) An injection well has mechanical integrity if:

(Internal)

(1) There is no significant leak in the casing, tubing or packer;

(b) One of the following methods must be used to evaluate the absence of significant leaks under paragraph (a)(1) of this section:

(1) Following an initial pressure test, monitoring of the tubing-casing annulus pressure with sufficient frequency to be representative, as determined by the Director, while maintaining an annulus pressure different from atmospheric pressure measured at the surface;

(2) Pressure test with liquid or gas; or

(3) Records of monitoring showing the absence of significant changes in the relationship between injection pressure and injection flow rate for the following Class II enhanced recovery wells:

(i) Existing wells completed without a packer provided that a pressure test has been performed and the data is available and provided further that one pressure test shall be performed at a time when the well is shut down and if the running of such a test will not cause further loss of significant amounts of oil or gas; or

(ii) Existing wells constructed without a long string casing, but with surface casing which terminates at the base of fresh water provided that local geological and hydrological features allow such construction and provided further that the annular space shall be visually inspected. For these wells, the Director shall prescribe a monitoring program which will verify the absence of significant fluid movement from the injection zone into an USDW.

(External)

(a)(2) There is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore.

c) One of the following methods must be used to determine the absence of significant fluid movement under paragraph (a)(2) of this section:

(1) The results of a temperature or noise log; or

(2) For Class II only, cementing records demonstrating the presence of adequate cement to prevent such migration; or

(3) For Class III wells where the nature of the casing precludes the use of the logging techniques prescribed at paragraph (c)(1) of this section, cementing records demonstrating the presence of adequate cement to prevent such migration;

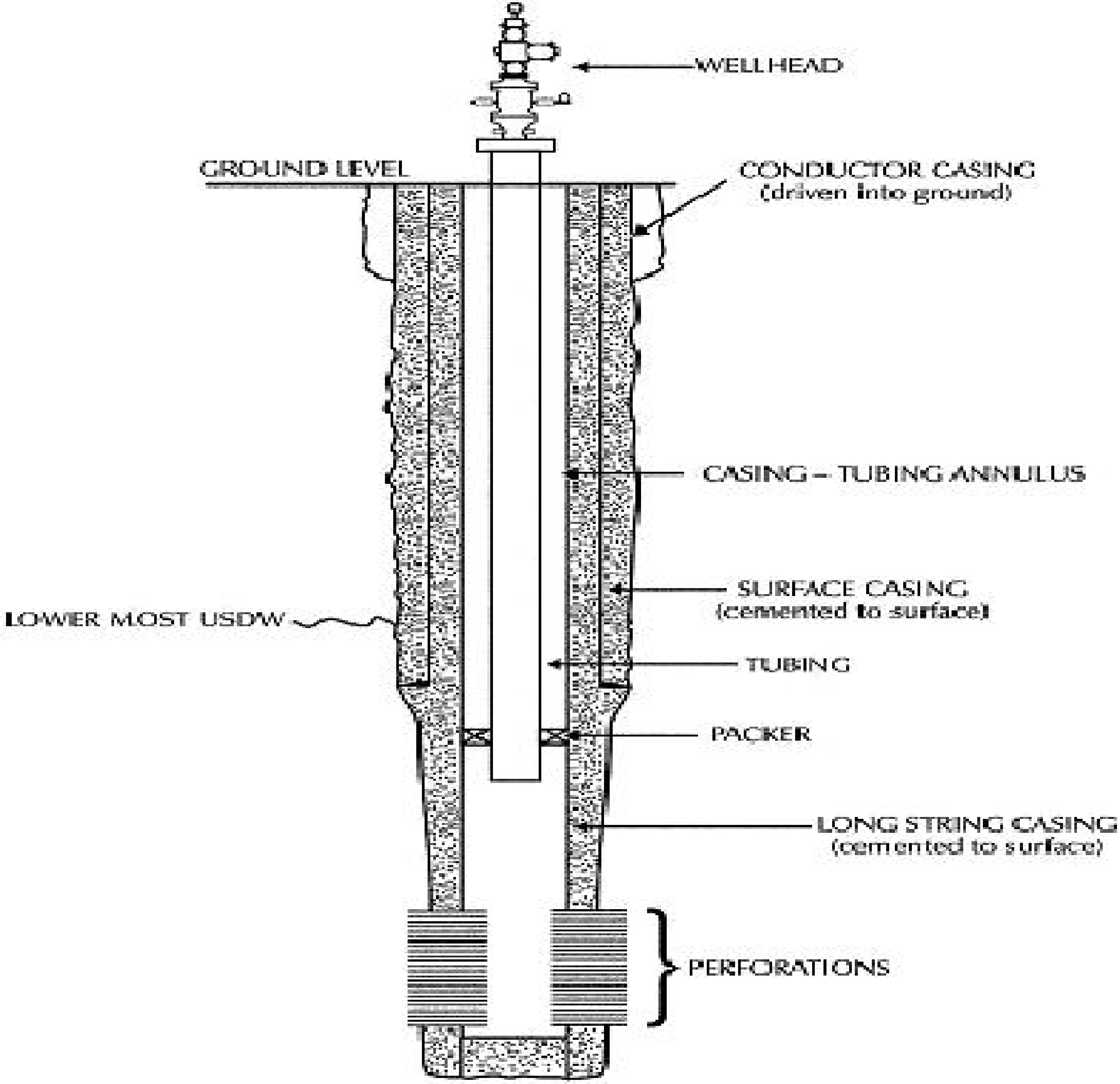
4) For Class III wells where the Director elects to rely on cementing records to demonstrate the absence of significant fluid movement, the monitoring program prescribed by §146.33(b) shall be designed to verify the absence of significant fluid movement.

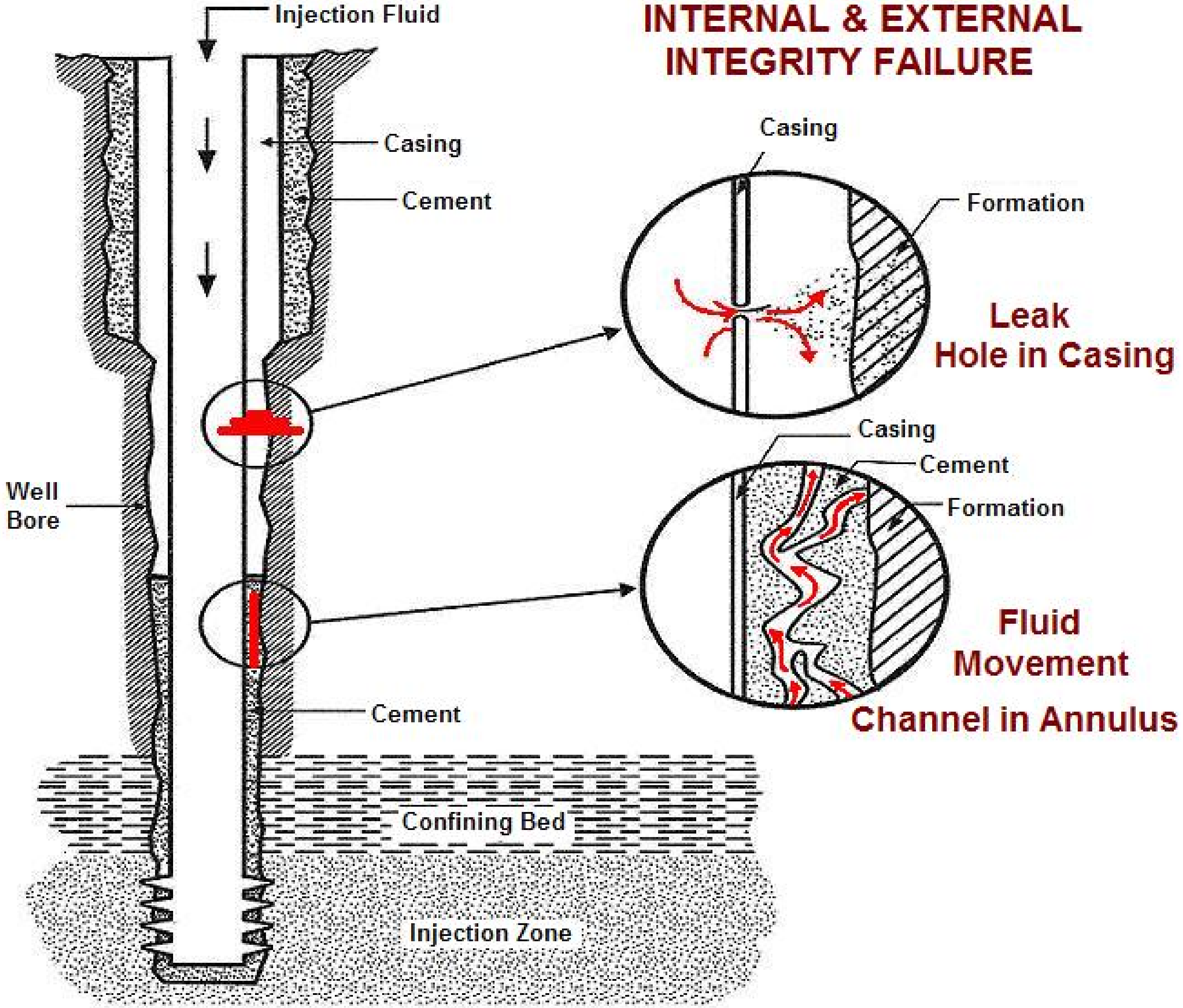
(Alternative tests)

(d) The Director may allow the use of a test to demonstrate mechanical integrity other than those listed in paragraphs (b) and (c)(2) of this section with the written approval of the Administrator. To obtain approval, the Director shall submit a written request to the Administrator, which shall set forth the proposed test and all technical data supporting its use. The Administrator shall approve the request if it will reliably demonstrate the mechanical integrity of wells for which its use is proposed. Any alternate method approved by the Administrator shall be published in the FEDERAL REGISTER and may be used in all States unless its use is restricted at the time of approval by the Administrator.

(e) In conducting and evaluating the tests enumerated in this section or others to be allowed by the Director, the owner or operator and the Director shall apply methods and standards generally accepted in the industry. When the owner or operator reports the results of mechanical integrity tests to the Director, he shall include a description of the test(s) and the method(s) used. In making his/her evaluation, the Director shall review monitoring and other test data submitted since the previous evaluation.

(f) The Director may require additional or alternative tests if the results presented by the owner or operator under §146.8(e) are not satisfactory to the Director to demonstrate that there is no movement of fluid into or between USDWs resulting from the injection activity.


WELLHEAD
GROUND LEVEL
CONDUCTOR CASING
(driven into ground)
CASING – TUBING ANNULUS
SURFACE CASING
(cemented to surface)
LOWER MOST USDW
TUBING
PACKER
LONG STRING CASING
(cemented to surface)
PERFORATIONS



Injection Fluid
INTERNAL & EXTERNAL
INTEGRITY FAILURE
Casing
Cement
Casing
Formation
Leak
Hole in Casing
Casing
Cement
Formation
Well
Bore
Fluid
Movement
Channel in Annulus
Cement
Confining Bed
Injection Zone

What are our main MI concerns?

1 Any **leaks** in the system?

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1 Any **leaks** in the system?

2 Is injected fluid **entering and remaining** in the approved interval?

What are our main MI concerns?

1 Any **leaks** in the system?

2 Is injected fluid **entering and remaining** in the approved interval?

3 Is there **crossflow** of fluid into USDWs?

What are our main MI goals?

1 Any **leaks** in the system?

(Internal MI)

Goal:

Prevention of leakage through the "walls" of the well (casing, tubing, etc.)

Prevention of Leakage through the "walls" of the well (casing, tubing, etc.).

How leakage can be discovered:

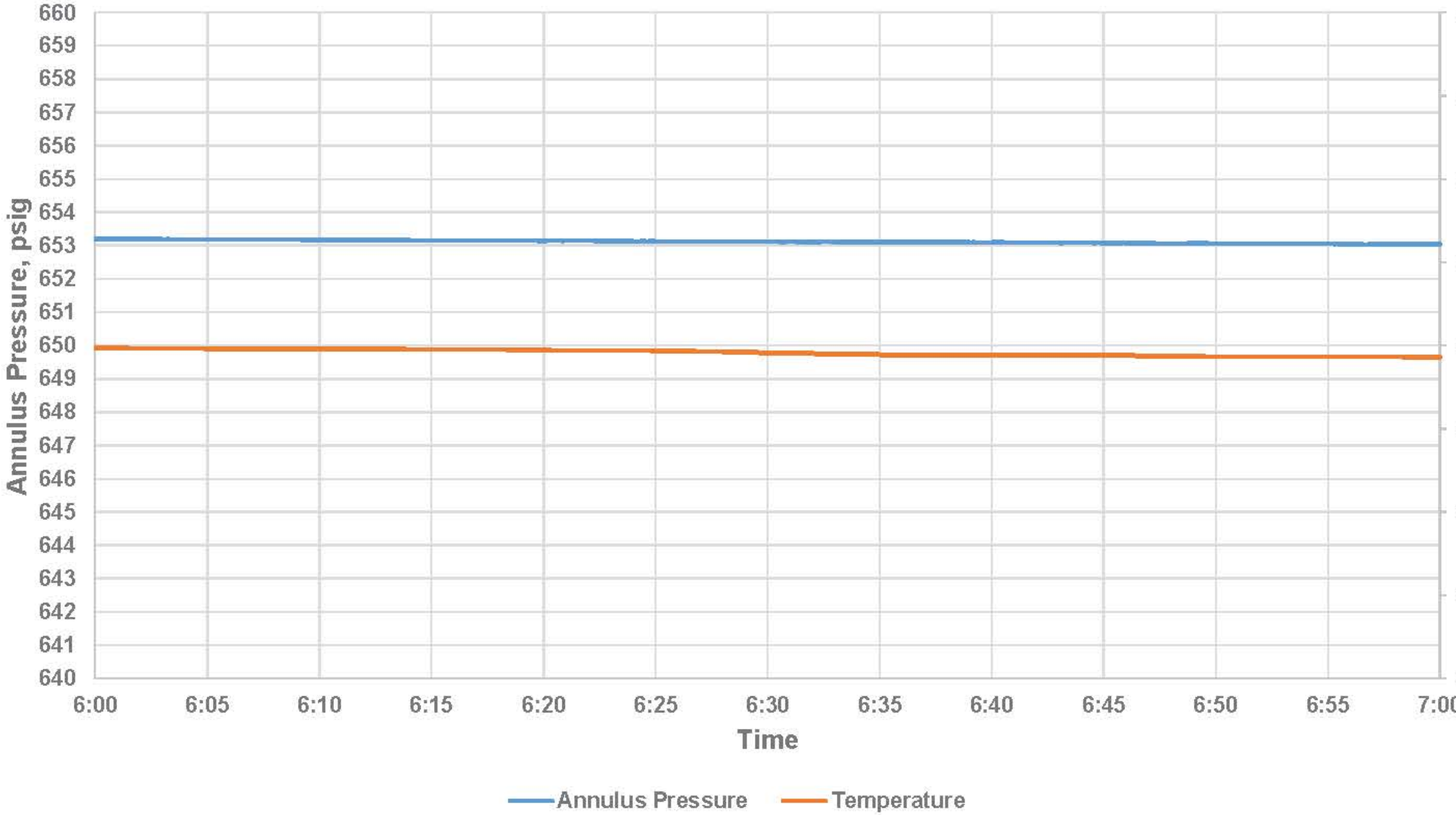
- pressure tests

INTERNAL MI ANNULUS PRESSURE TEST

- Tests the tubing, casing and packer for leaks.
- Testing requirements vary by well Class and UIC program requirements. These vary by State or Tribe.
- Typically the casing/tubing annulus is pressured to the maximum allowable injection pressure to ensure the casing can withstand this pressure should the tubing or packer fail. Director variances can also be allowed.
- The test length is typically 30 minutes to 1 hour.
- Test failure is typically a pressure loss of > 5 – 10%
- It is a good practice to observe the fluid flowback when the pressure is released as this will help determine the amount of the annulus being tested and can potentially spot an obstruction or “misplaced” packer

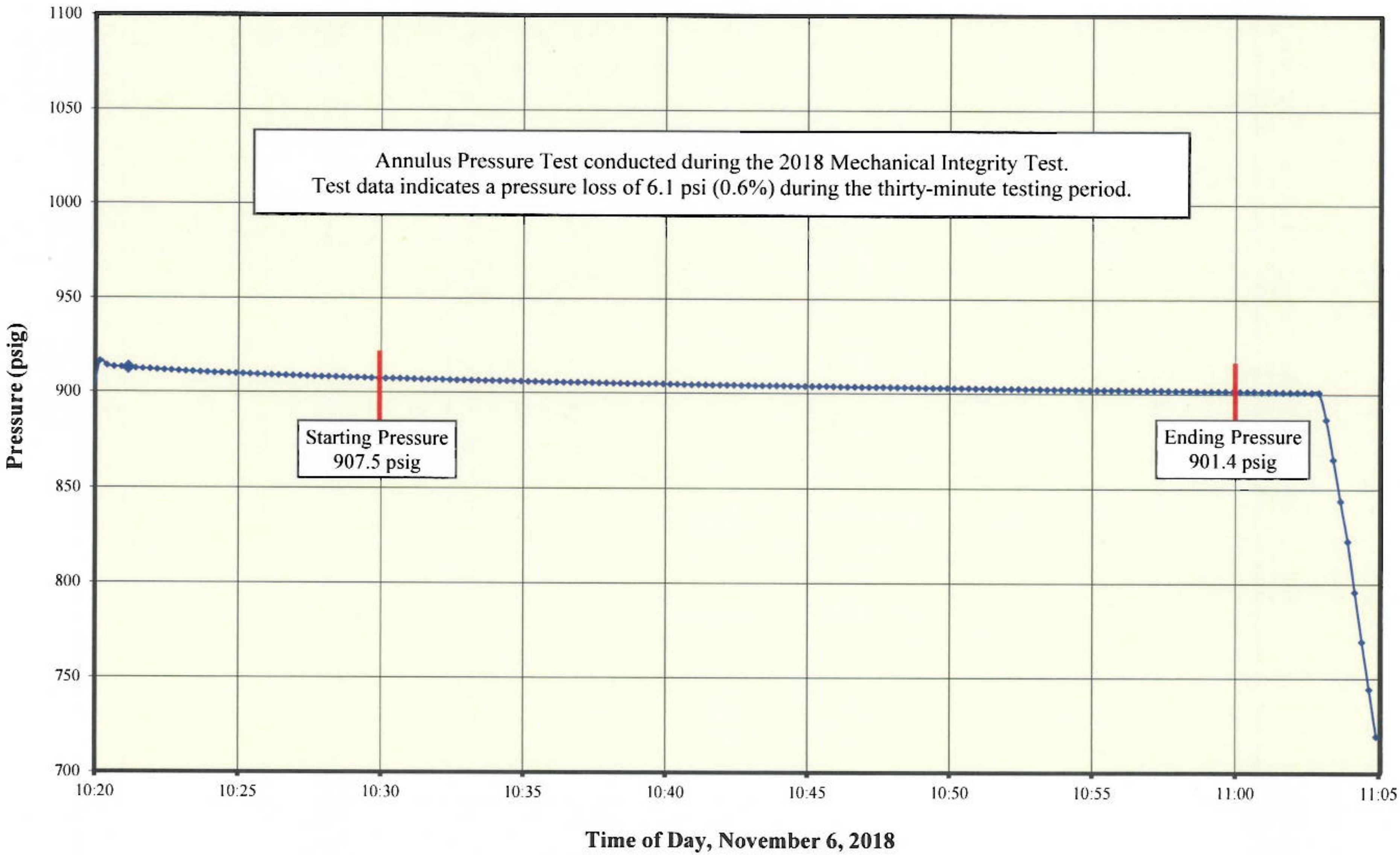
January 23, 2018

(Beginning Pressure = 653.20 psi & Ending Pressure = 653.03 psi;
Beginning Temperature = 44.85°F & Ending Temperature = 44.30°F)



Revised 01-31-18

Annulus Pressure Test



Prevention of Leakage through the "walls" of the well (casing, tubing, etc.).

How leakage can be discovered:

- pressure tests
- downhole logging (discussed later)

Prevention of Leakage through the "walls" of the well (casing, tubing, etc.).

How leakage can be discovered:

- pressure tests
- downhole logging
- monitoring of injection activities.
  - Annulus pressure
  - Injection pressure/rate relationship

What are our main MI Goals?

Prevention of Fluid Movement through Casing/Wellbore Annular Space

2 Is injected fluid **entering and remaining** in the approved interval?

(External MI)

What are our main MI Goals?

Prevention of Fluid Movement through Casing/Wellbore Annular Space

2 Is injected fluid **entering and remaining** in the approved interval?

(External MI)

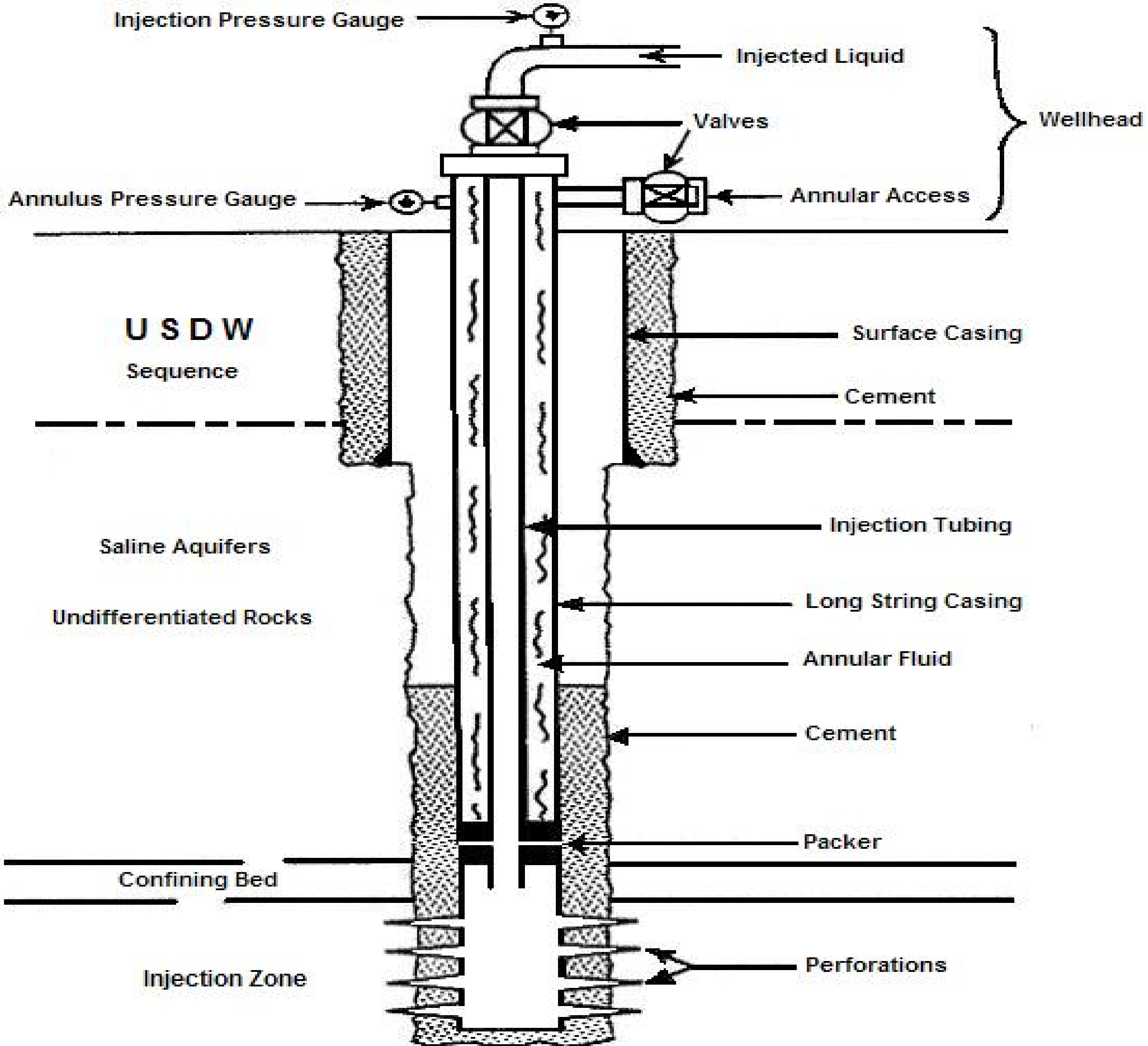
3 Is there **crossflow** of fluid into USDWs?

(External MI)

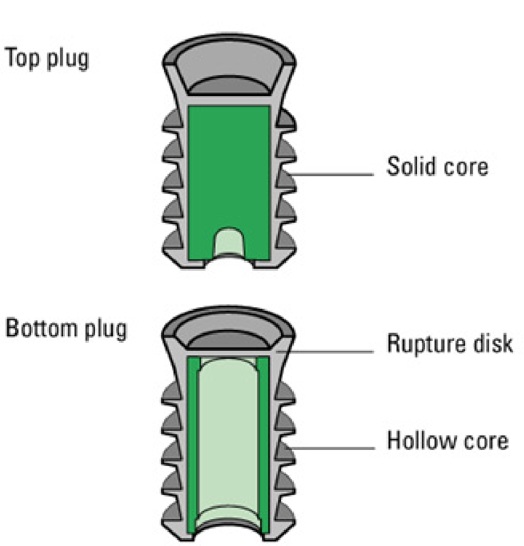
What are our main MI Goals?

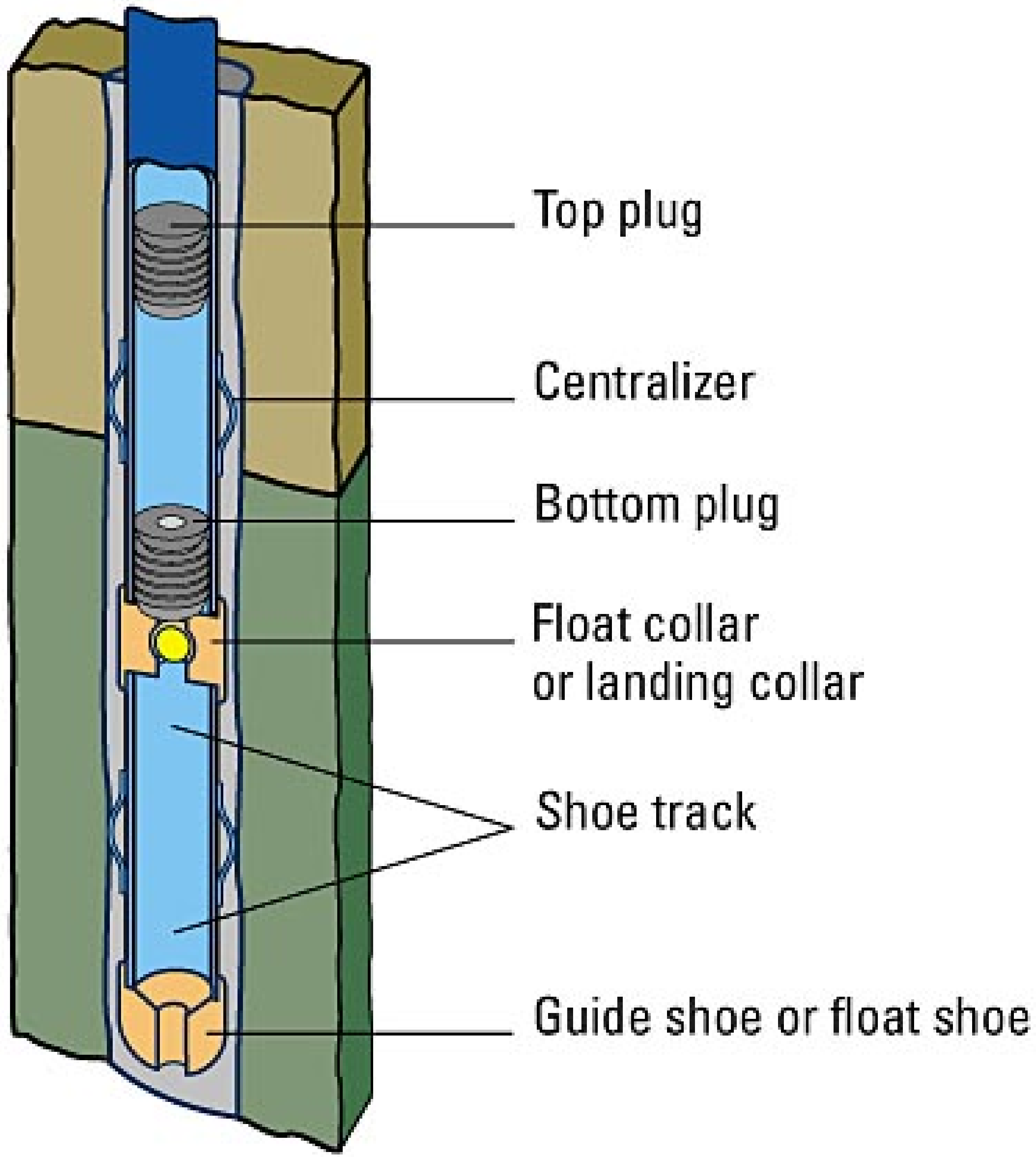
Prevention of Fluid Movement through Casing/Wellbore Annular Space

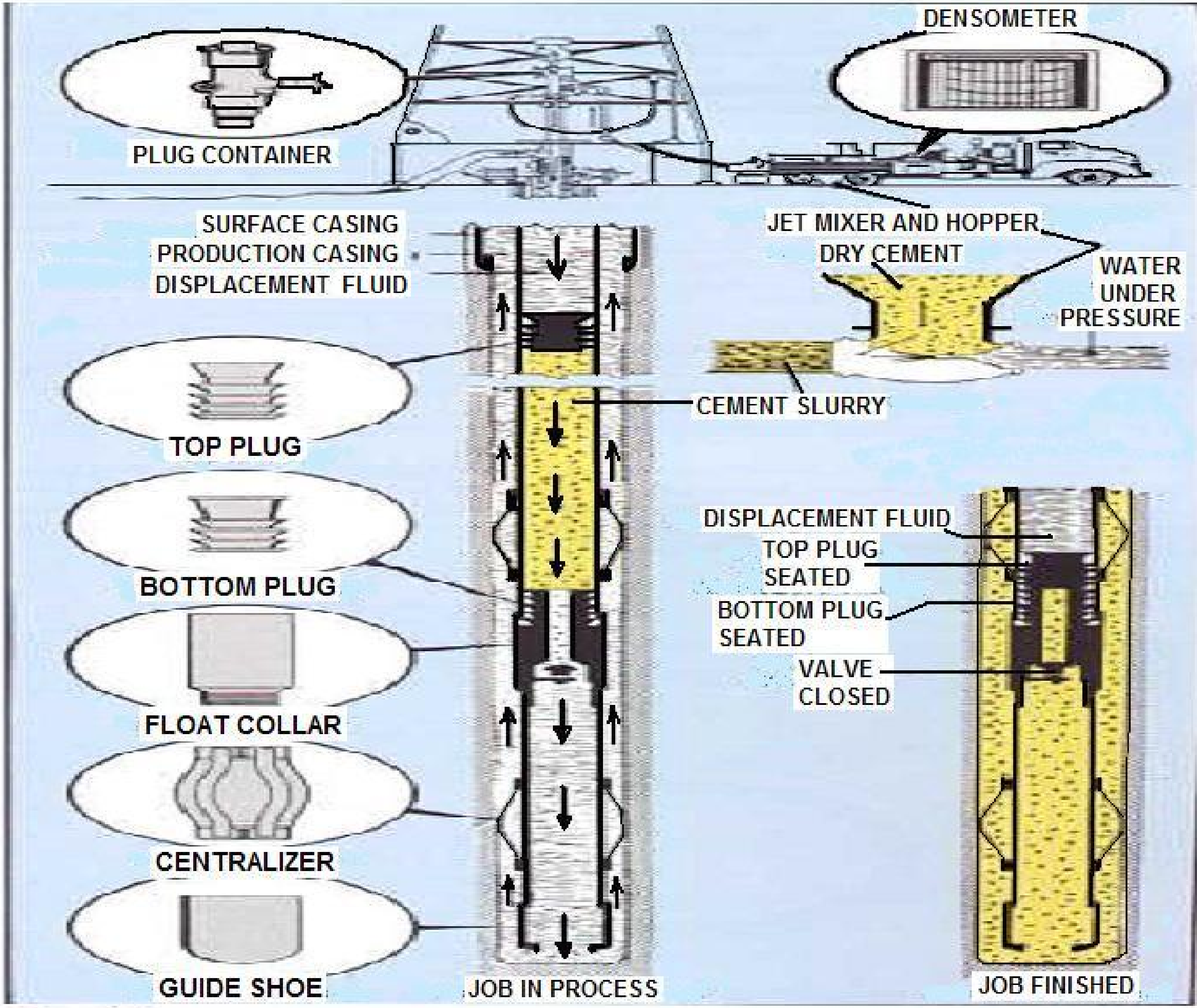
→ **Proper cementing and construction**


Injection Pressure Gauge
Injected Liquid
Valves
Wellhead
Annulus Pressure Gauge
Annular Access
U S D W
Sequence
Surface Casing
Cement
Injection Tubing
Saline Aquifers
Long String Casing
Undifferentiated Rocks
Annular Fluid
Cement
Packer
Confining Bed
Injection Zone
Perforations

Casing Cementing Operations

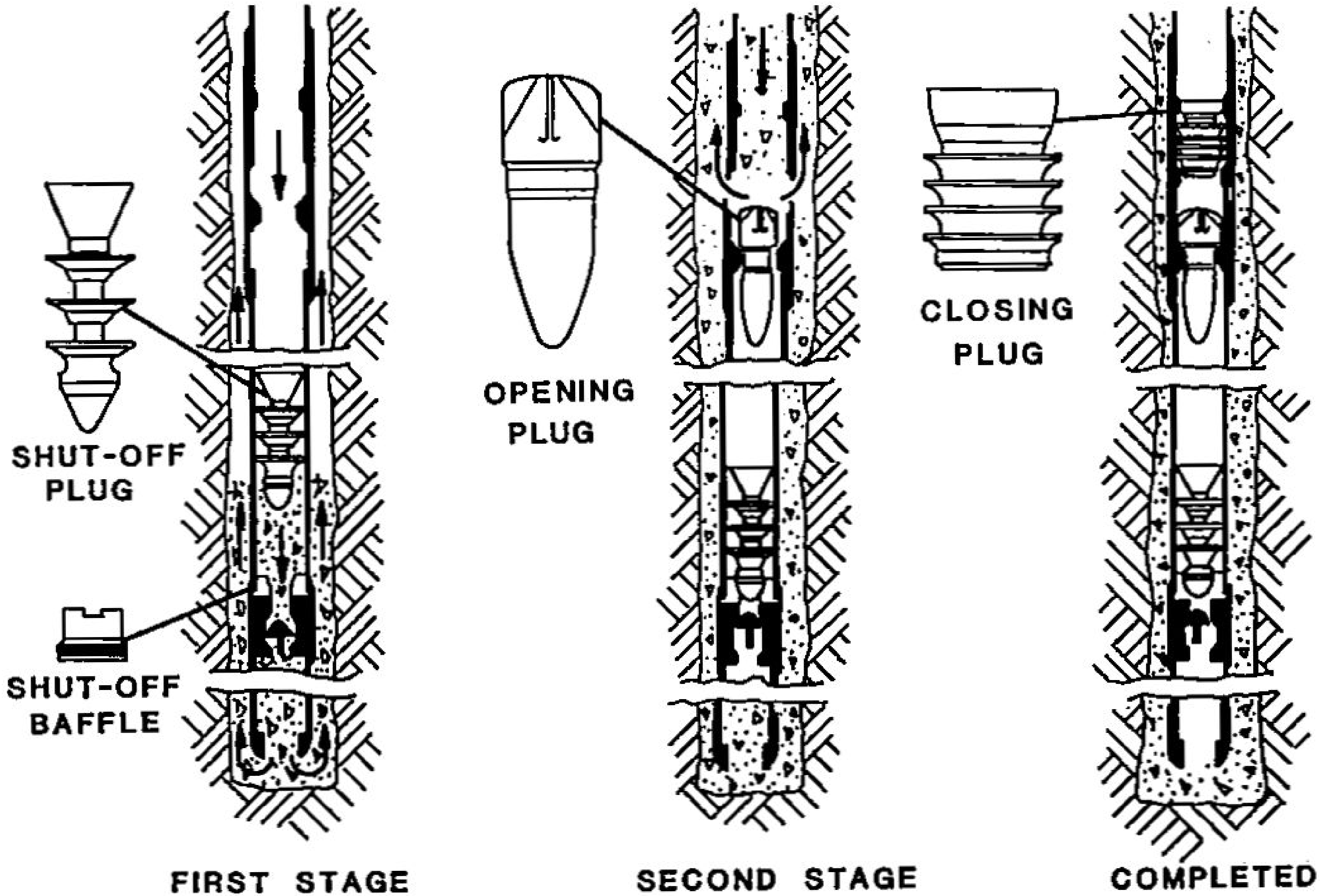


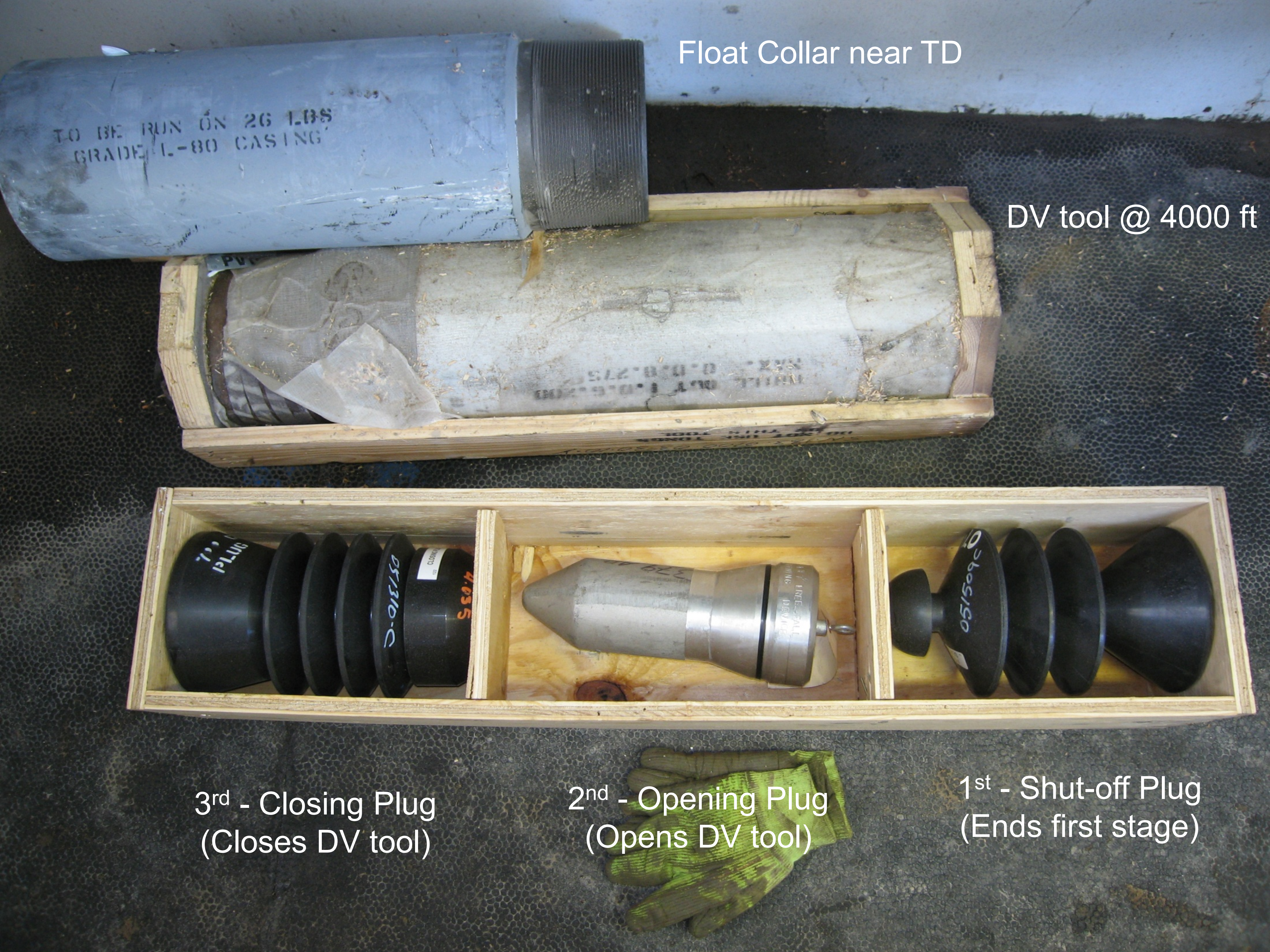




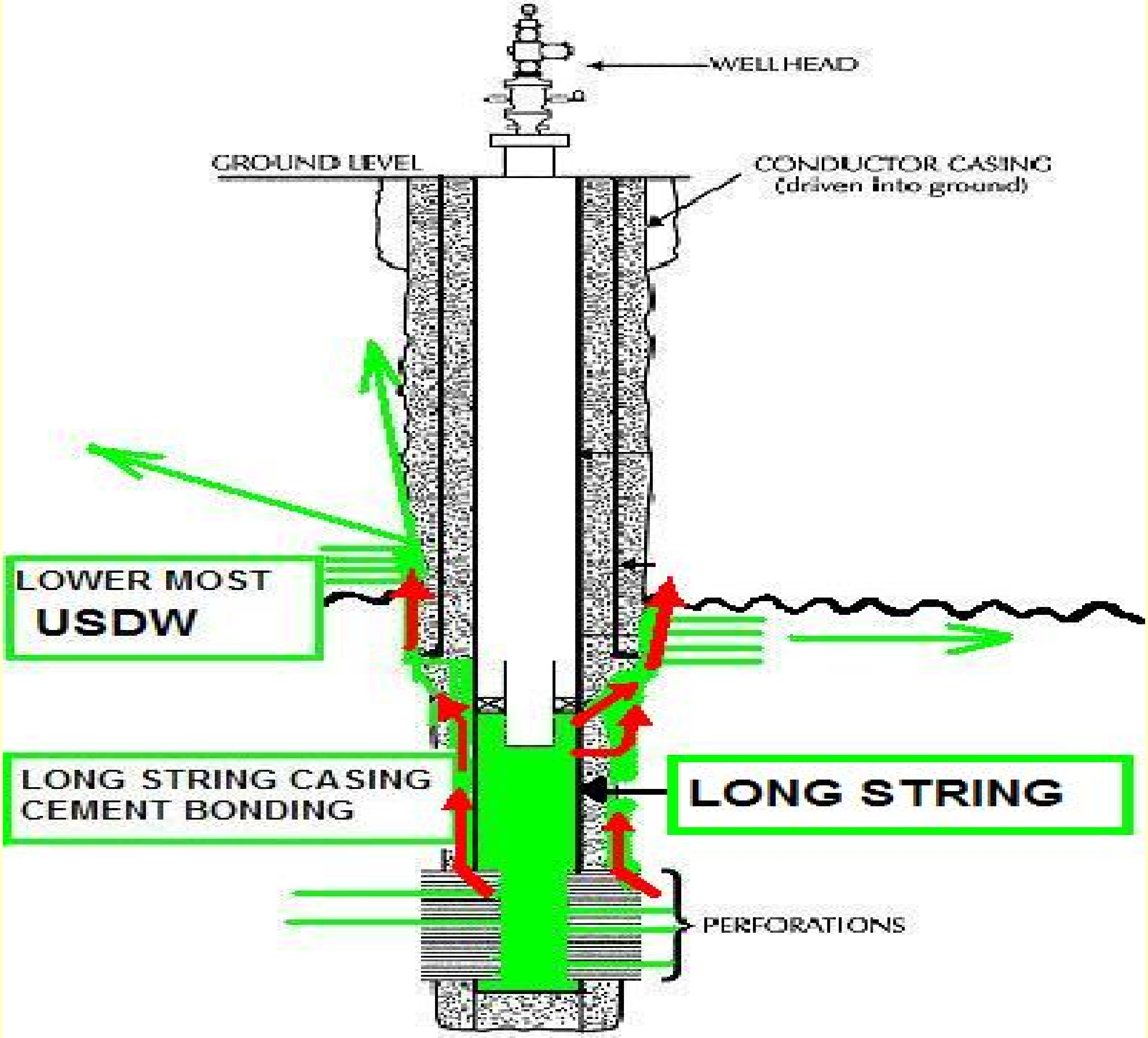
DENSOMETER
PLUG CONTAINER
SURFACE CASING
PRODUCTION CASING
DISPLACEMENT FLUID
JET MIXER AND HOPPER
DRY CEMENT
WATER
UNDER
PRESSURE
CEMENT SLURRY
TOP PLUG
BOTTOM PLUG
FLOAT COLLAR
CENTRALIZER
GUIDE SHOE
DISPLACEMENT FLUID
TOP PLUG
SEATED
BOTTOM PLUG
SEATED
VALVE
CLOSED
JOB IN PROCESS
JOB FINISHED

Two-stage Cementing Tools: (Float Collar, DV tool, and Plugs)




Float Collar near TD
TO BE RUN ON 26 LBS
GRADE L-80 CASING
DV tool @ 4000 ft
3rd - Closing Plug
(Closes DV tool)
2nd - Opening Plug
(Opens DV tool)
1st - Shut-off Plug
(Ends first stage)


Centralizers
FX4
OFF ROAD
BFGoodrich


WELLHEAD
GROUND LEVEL
CONDUCTOR CASING
(driven into ground)
LOWER MOST
USDW
LONG STRING CASING
CEMENT BONDING
LONG STRING
PERFORATIONS

Cement Bond Log

(CBL)

- Cement needs to set properly before a cement integrity log is run. This can take from 10 to 50 hours for typical cement jobs.

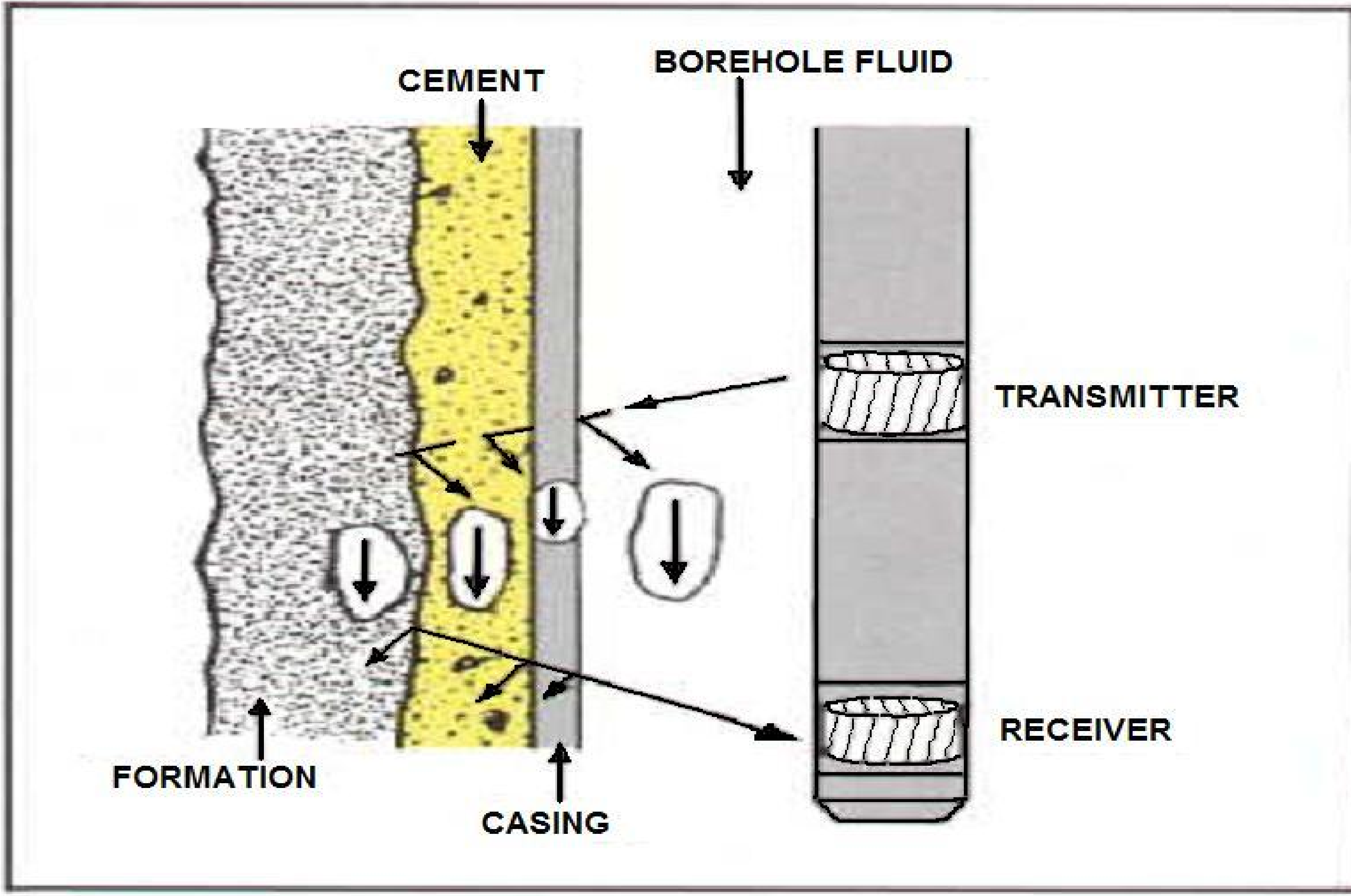
- Full compressive strength is reached in 7 to 10 days. The setting time depends on the type of cement, temperature, pressure, and the use of setting accelerants.

- Excess pressure on the casing should be avoided during the curing period so that the cement bond to the pipe is not disturbed.

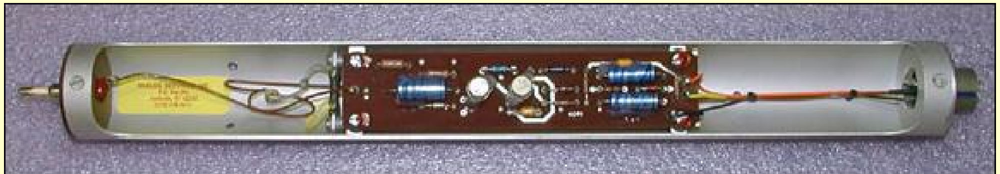
- Cement bond logs were run as early as 1958 with early sonic logs and the temperature log was used to find the cement top beginning in 1933.

- Cement integrity logs are run to determine the quality of the cement bond to the casing, to evaluate cement fill-up between the casing and the wellbore rock and to evaluate the cement bond to the wellbore rock.

- A poor cement bond may allow unwanted fluids to enter the wellbore or injected fluid to leave the injection interval.



CEMENT LOGGING PRINCIPLES



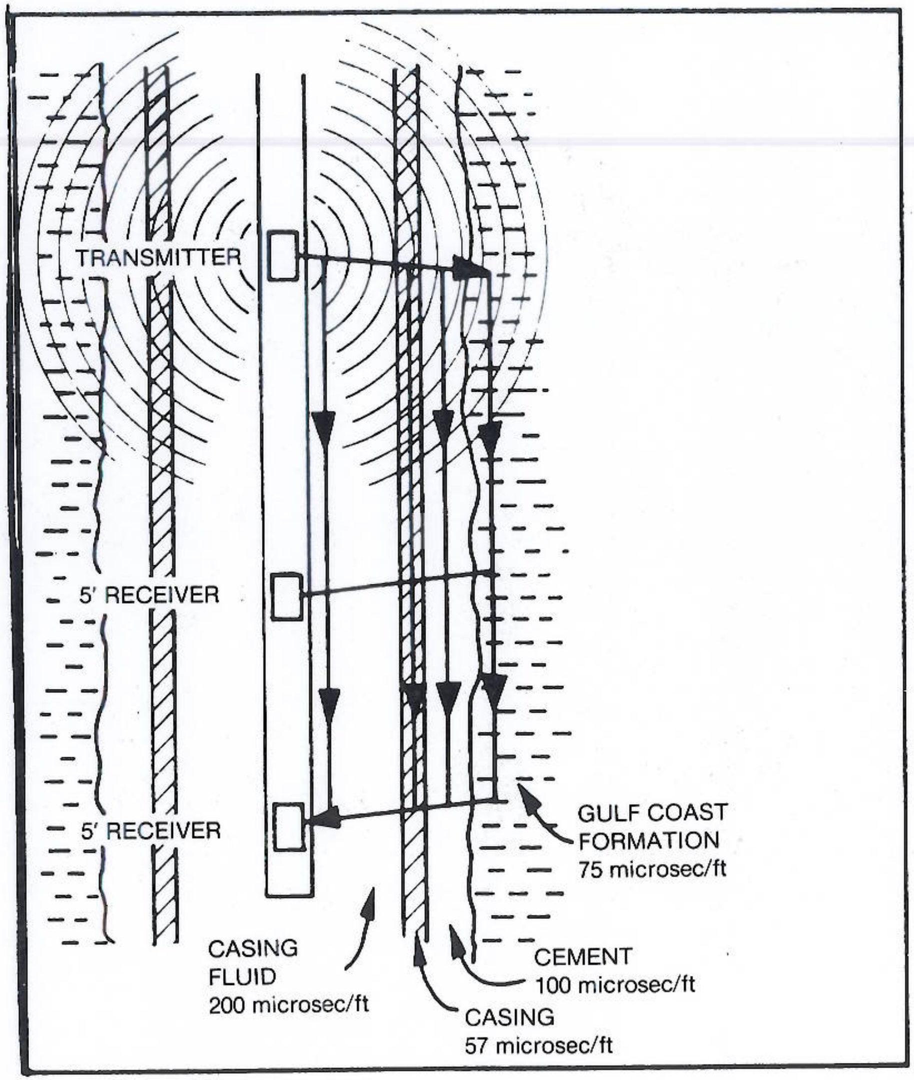


Figure 78. Typical transit times for various media inspection by the cement bond tool (Schlumberger, no date).

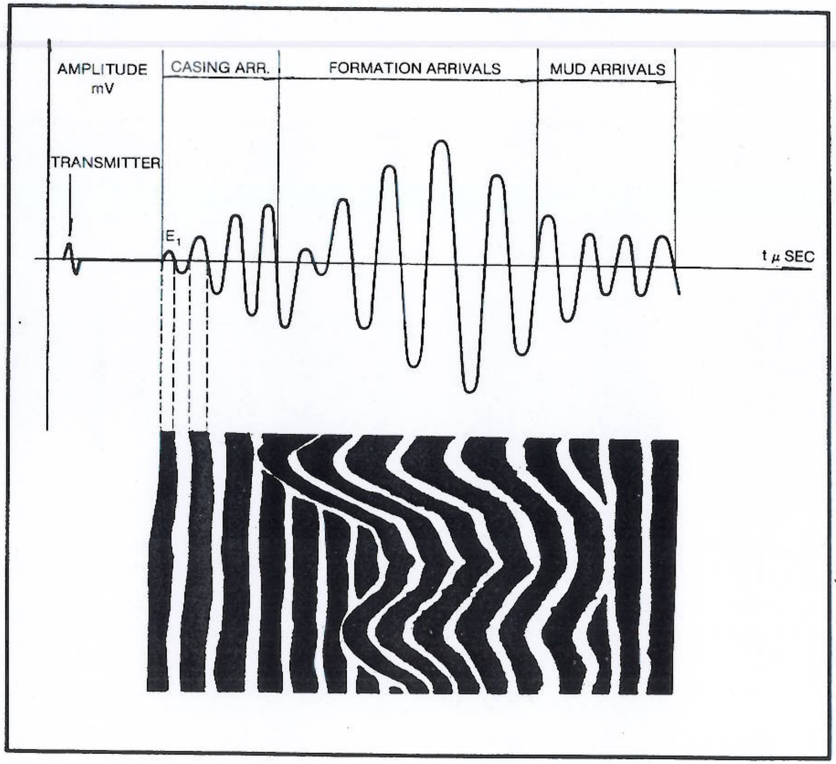
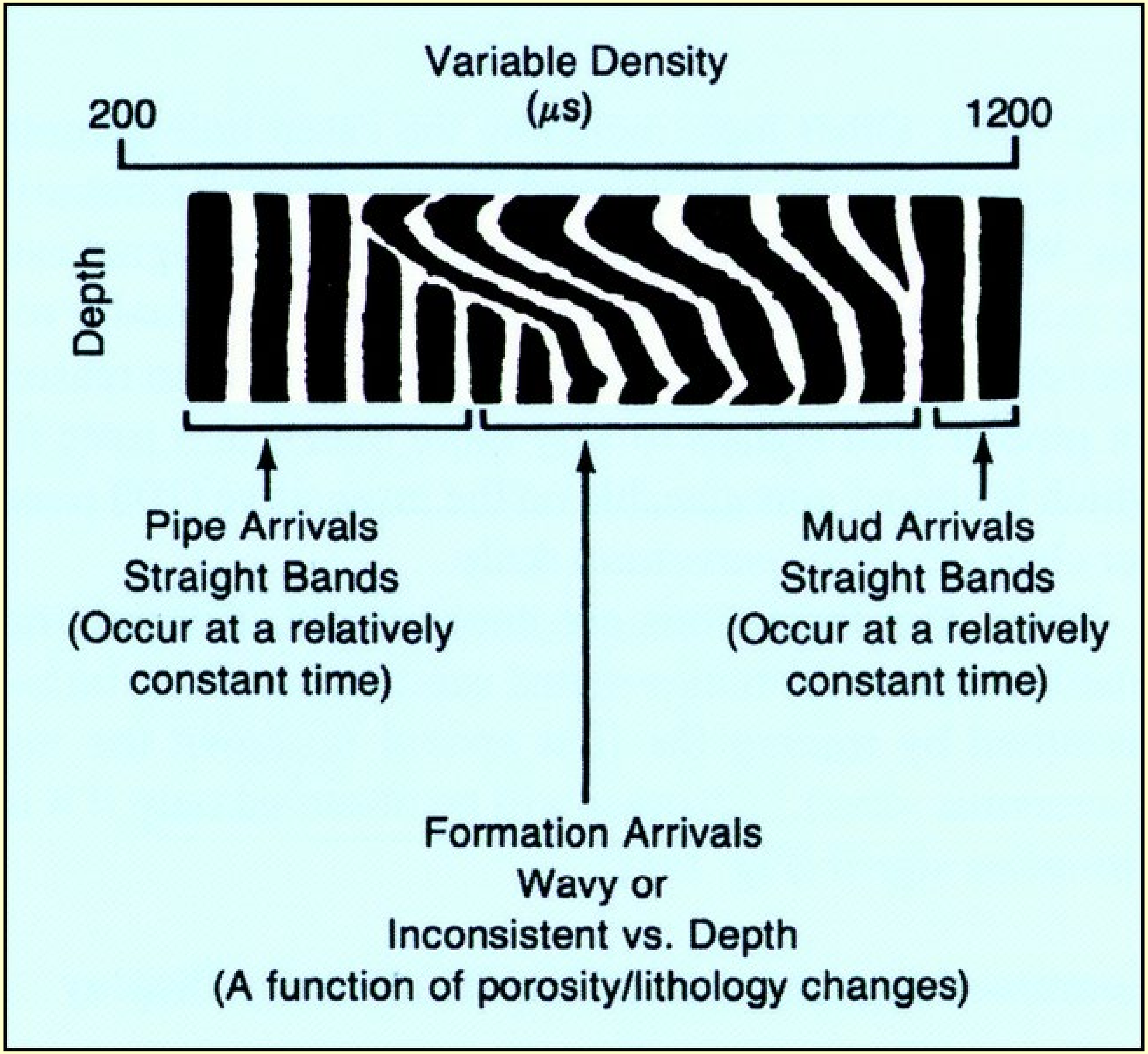


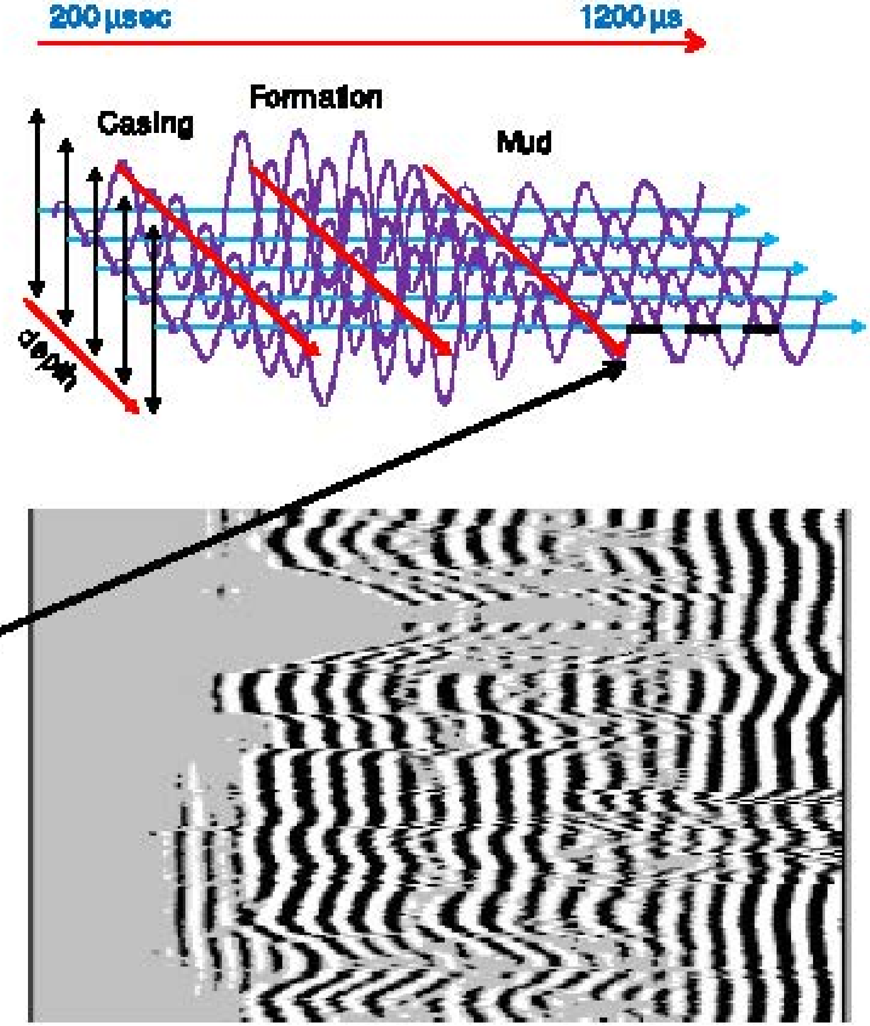
Figure 80. Principle of operation of the variable density log (Schlumberger, 1976).

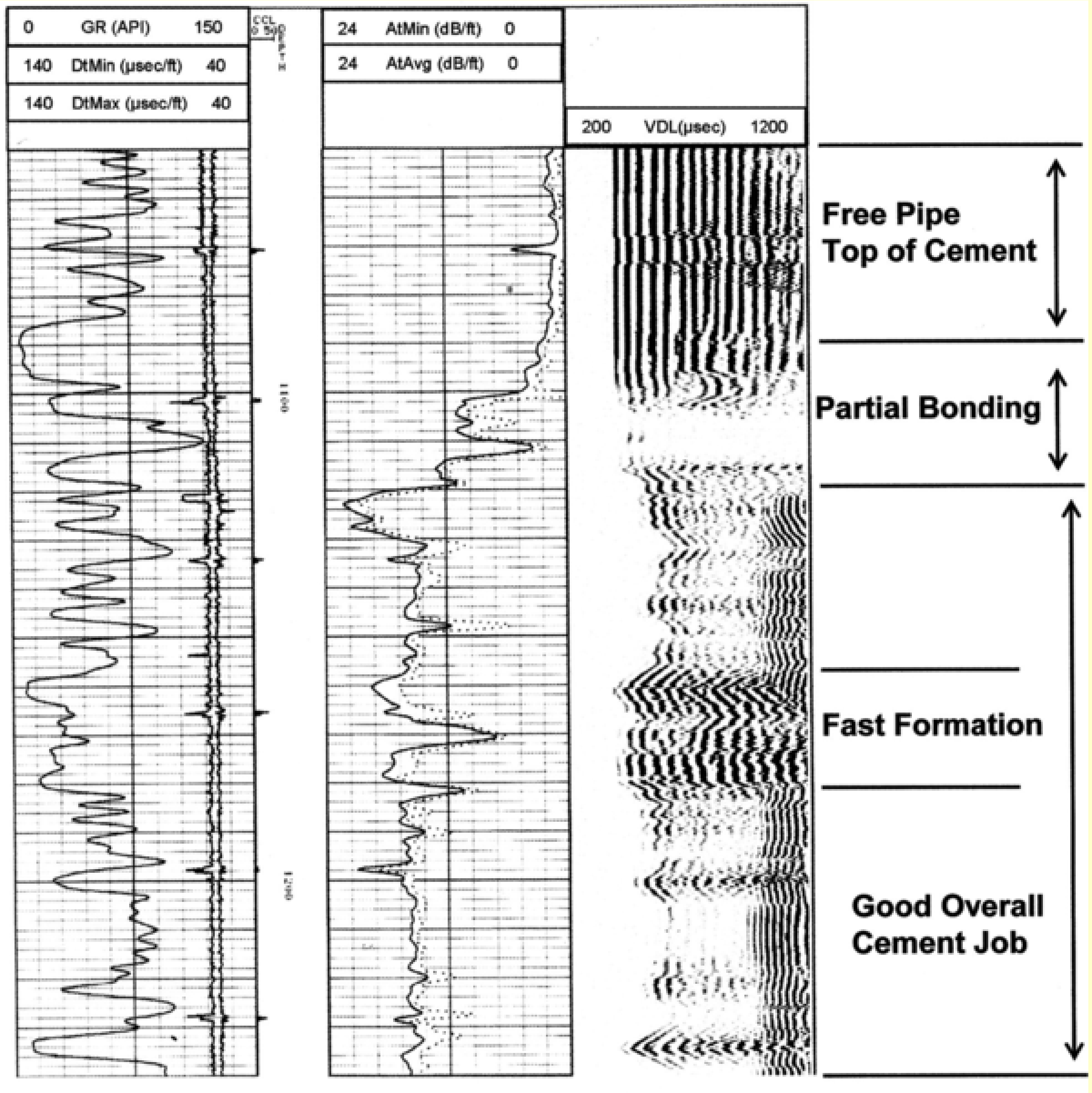


Identification of important features on a variable-density log (VDL) (courtesy of Baker Atlas).

VDL
Variable Density Log

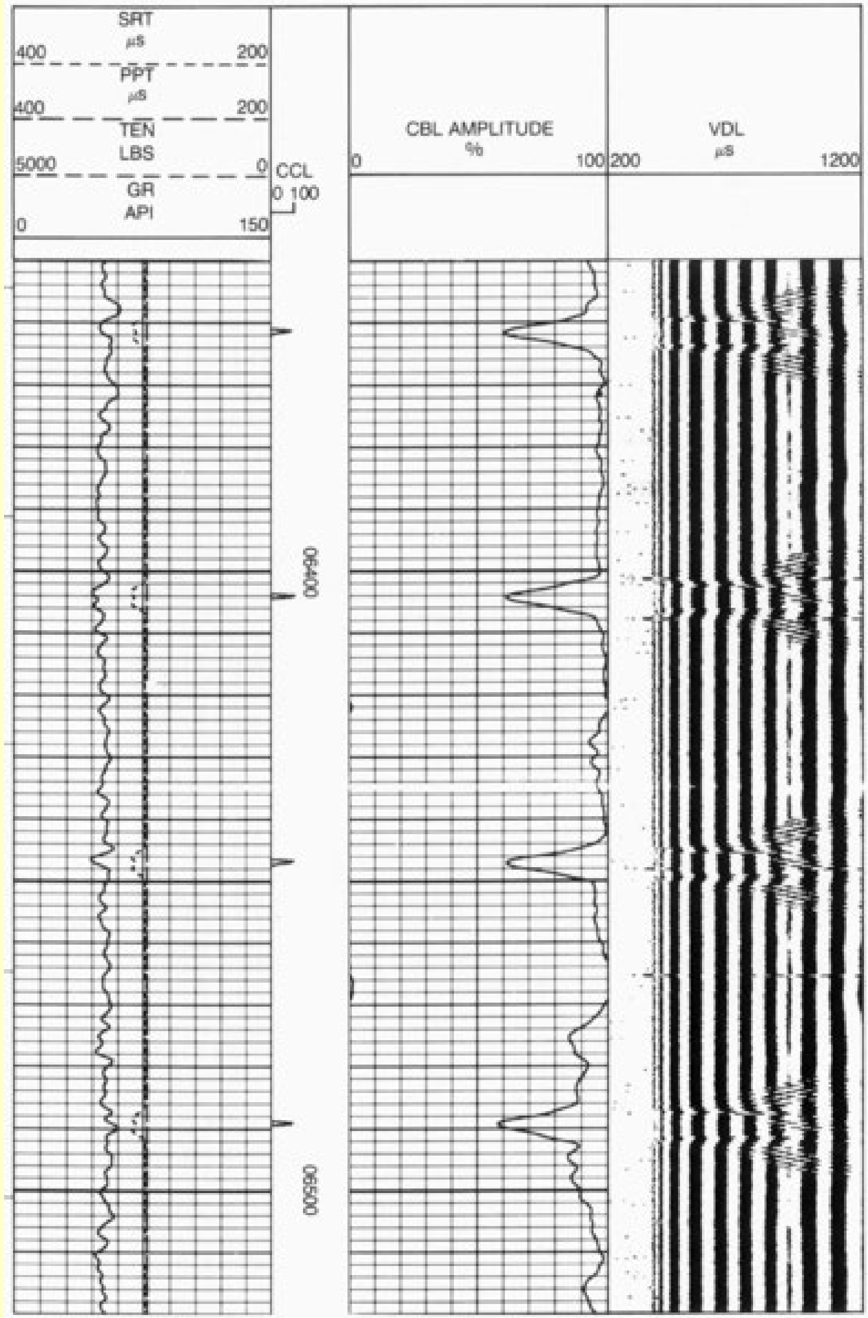
- VDL displays multiple "slices of data" side by side
  - 200 – 1200 µs for 3' VDL
- Arrival patterns start to become apparent
- To make a 2D picture of the 3D image:
  - Positive peaks are shaded black
  - Negative peaks are shaded white
- Casing arrivals should be consistent but formation arrivals "*should*" change with lithology



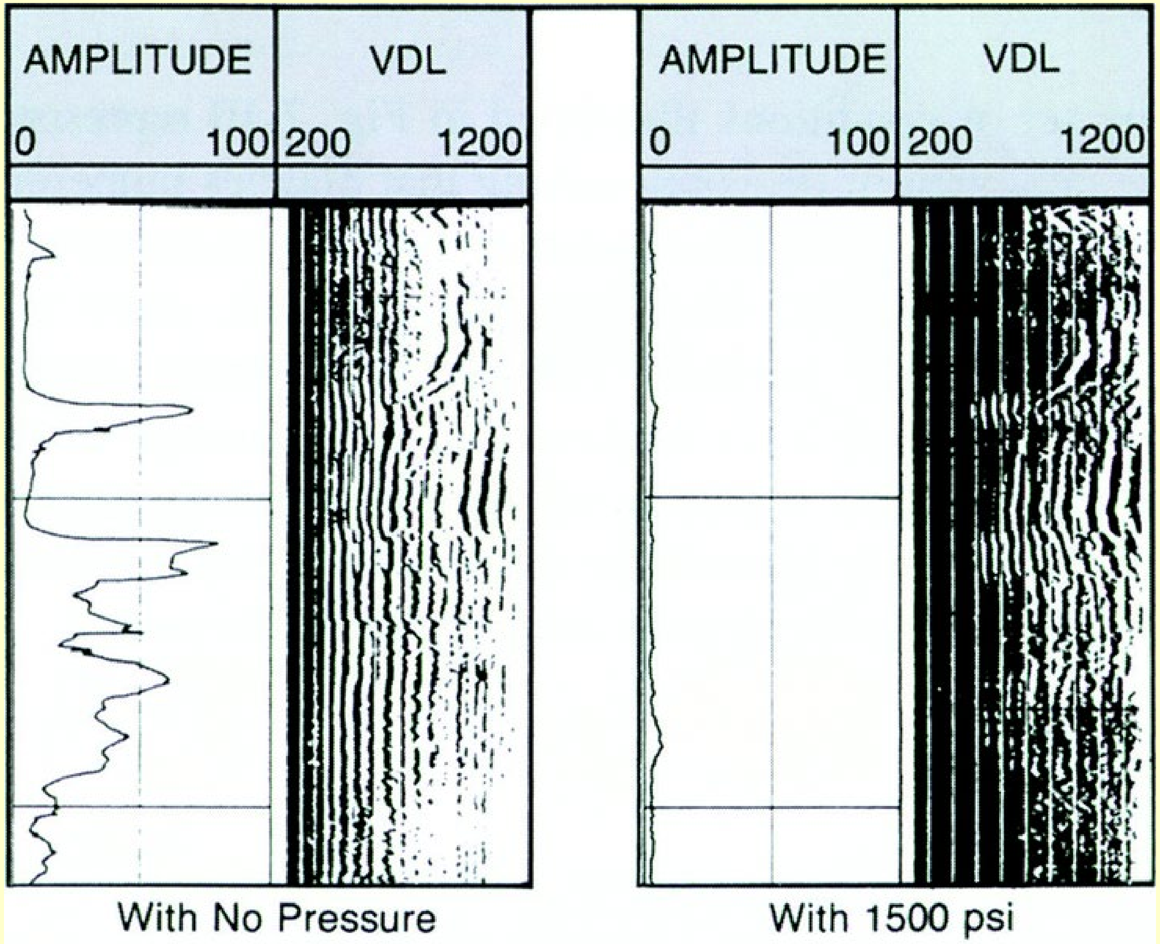


Typical cement-bond log presentation (courtesy of Baker Atlas).

In cases of poor bonding, casing-collar signals may also be identified as "w" patterns (anomalies)



Field example showing microannulus effect on amplitude and VDL log displays (courtesy of Baker Atlas).



Pressuring the casing improves the acoustic coupling to the formation and the casing signal will decrease and the formation signal will become more obvious

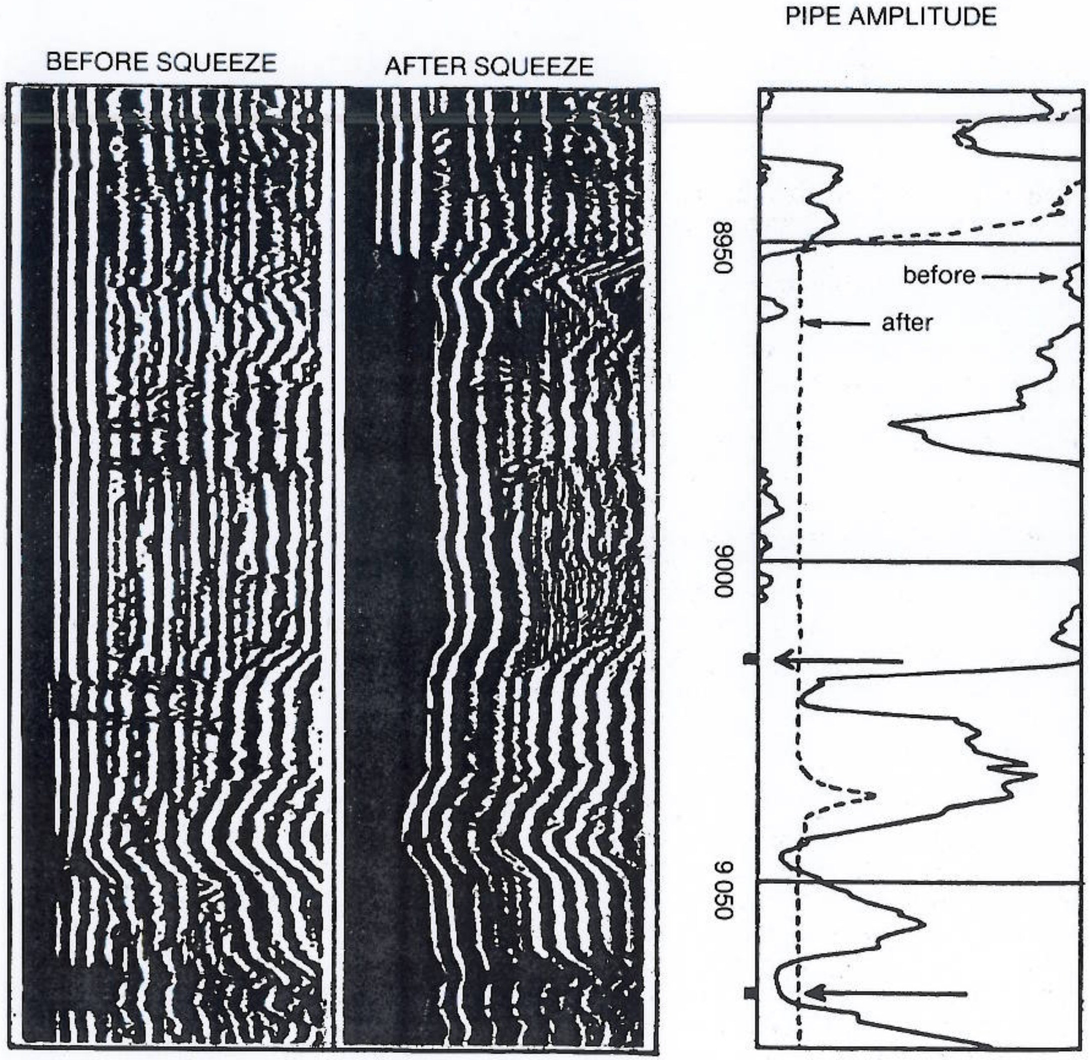
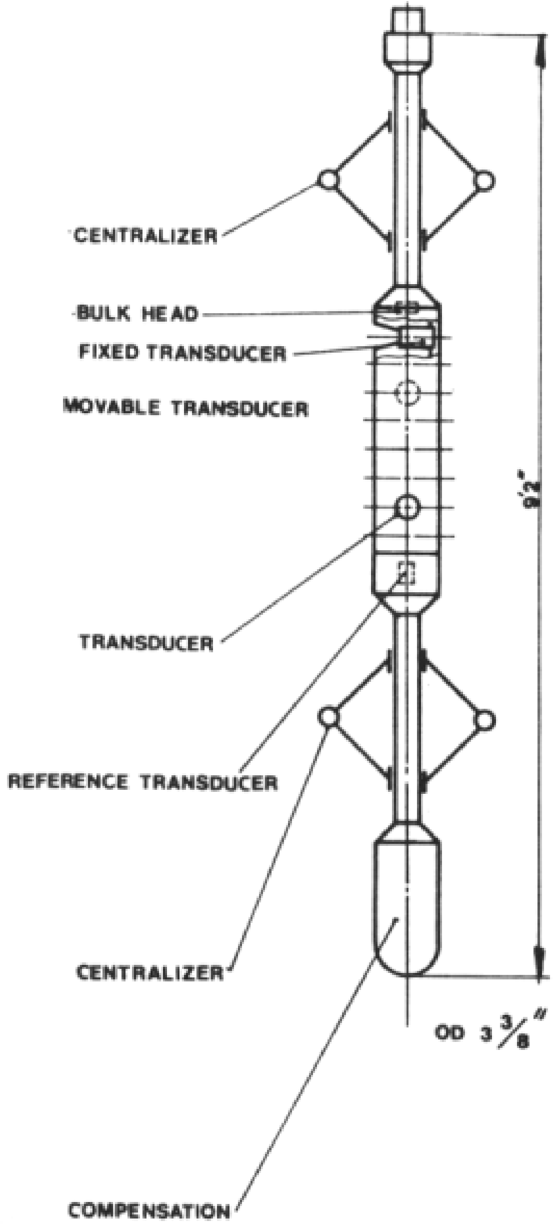


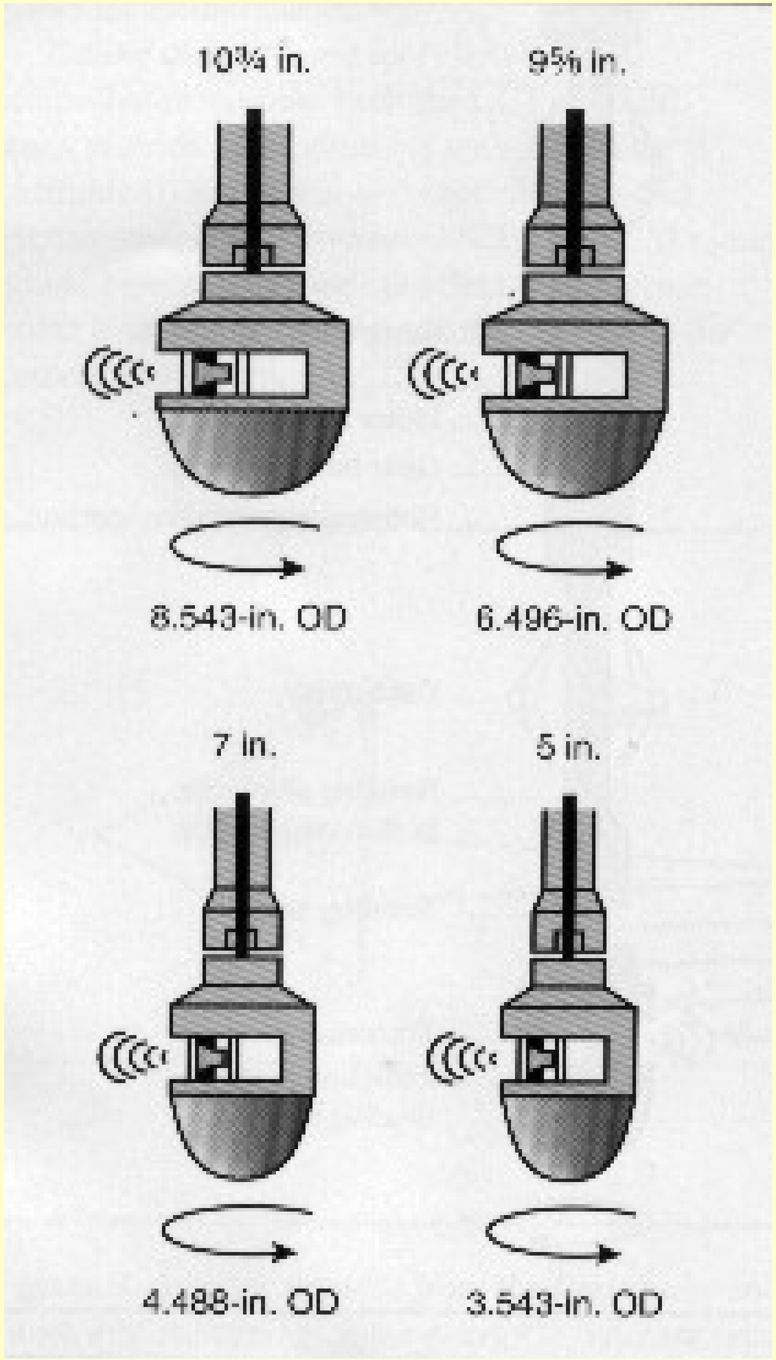
Figure 90. Elimination of a channel by cement squeezing (Walker, 1968).

CEMENT EVALUATION TOOL

(CET)



Cement Evaluation Tool
(Courtesy of Schlumberger)



CET
PURPOSE

- SAME AS **CEMENT BOND LOG (CBL)** ONLY MORE ADVANCED PRINCIPLE
- INVESTIGATES CEMENT **RADIALLY**
- MEASURES CASING **DIAMETER**, CASING **ROUNDNESS**, AND TOOL **ECCENTERING**

CET
PRINCIPLE OF OPERATION

- ULTRA SONIC ENERGY MAKES CASING **RESONATE**

- **RATE OF DAMPENING** IS MEASURED

- RADIAL INVESTIGATION IS ACHIEVED WITH **9 TRANSDUCERS**

CET
FACTORS AFFECTING MEASUREMENT

- TYPE OF **FLUID** IN WELL
- **THICKNESS** OF CASING WALL
- AMOUNT OF **CEMENT BONDED** TO CASING
- **COMPRESSIVE STRENGTH** OF CEMENT

CET
EQUIPMENT

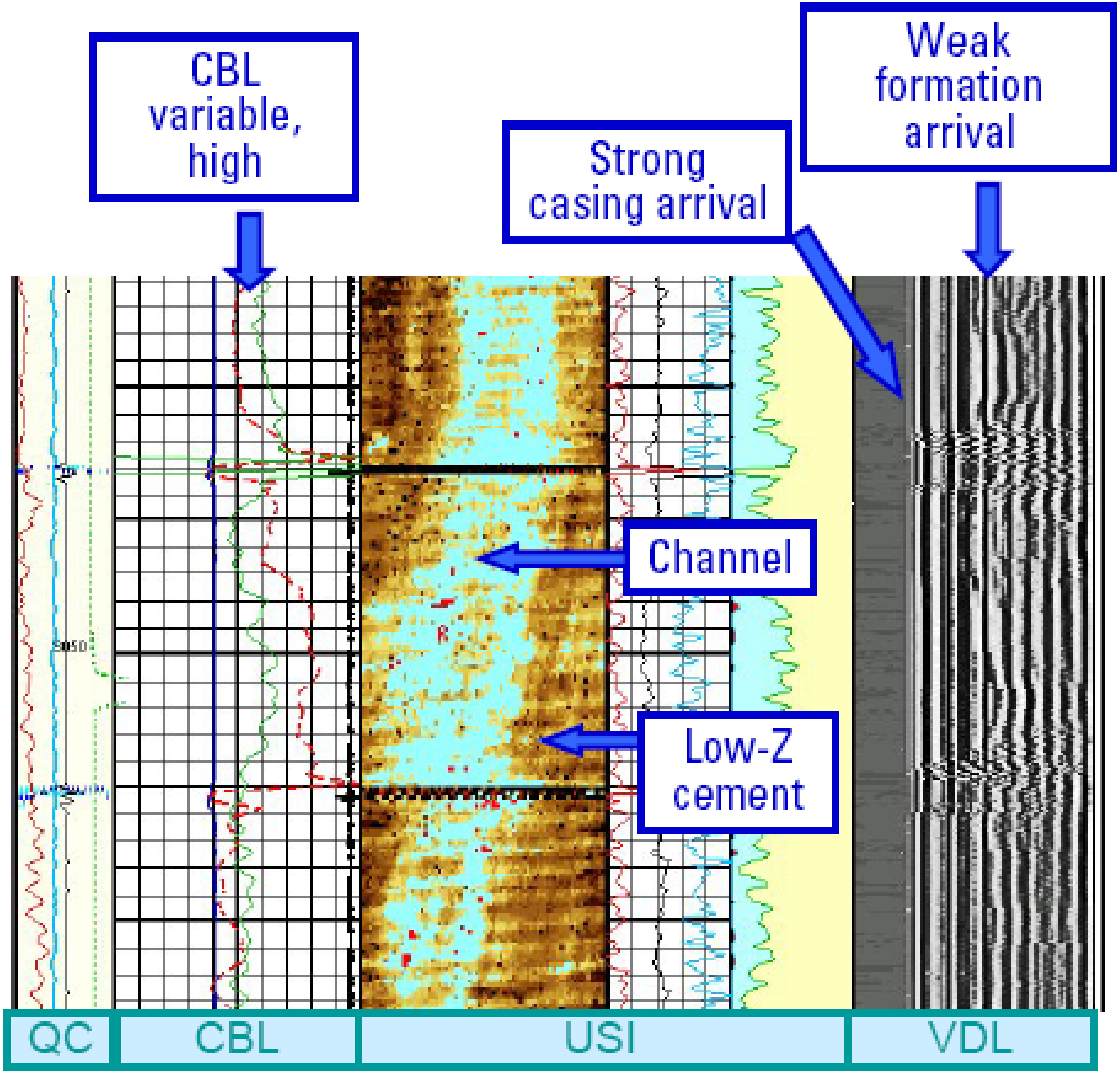
- 8 TRANSDUCERS IN **HELICAL PATTERN**
- 1 TRANSDUCER (MEASURES **FLUID SOUND VELOCITY**)
- **TOOL SIZE** = 3-3/8 inches to 4 inches

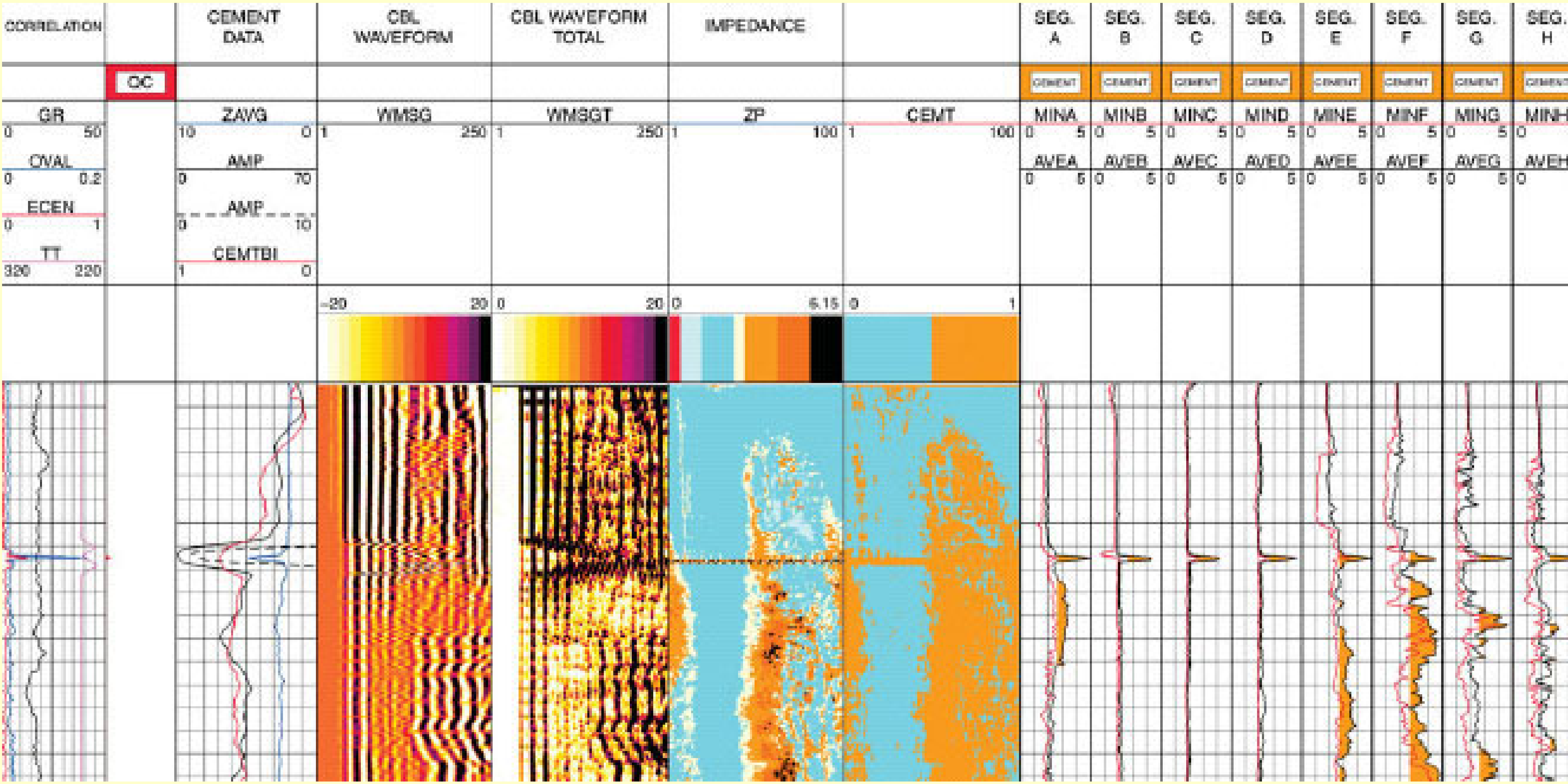
CET
PROCEDURE

- REMOVE **TUBING**
- ENSURE TOOL IS **CENTRALIZED**
- LOG ONLY IN **LIQUID FILLED** CASING
- RUN WITH CASING **COLLAR LOCATOR** AND **GAMMA RAY**

CET
ADVANTAGES

- **RADIAL** CEMENT EVALUATION
- CEMENT **CHANNEL IDENTIFICATION**
- IMMUNE TO **MICROANNULUS**
- NOT AFFECTED BY **"FAST FORMATIONS"**
- "EASIER" TO **INTERPRET**


CBL variable, high
Strong casing arrival
Weak formation arrival
Channel
Low-Z cement
QC
CBL
USI
VDL


CORRELATION
CEMENT DATA
CBL WAVEFORM
CBL WAVEFORM TOTAL
IMPEDANCE
SEG. A
SEG. B
SEG. C
SEG. D
SEG. E
SEG. F
SEG. G
SEG. H
QC
GR
0 50
OVAL
0 0.2
ECEN
0 1
TT
320 220
ZAVG
10 0
AMP
0 70
AMP
0 10
CEMTBI
1 0
WMSG
1 250
WMSGT
1 250
ZP
1 100
CEMT
1 100
MINA
MINB
MINC
MIND
MINE
MINF
MING
MINH
AVEA
AVEB
AVEC
AVED
AVEE
AVEF
AVEG
AVEH
-20 20
0 20
0 6.15
0 1

CASING INSPECTION LOG ULTRA SONIC PULSE ECHO

AH CABLEHEAD

Diameter : 1.37"

SWIVEL SINGLE CONDUCTOR

Diameter : 3.13"

HRVTM ELECTRONICS

Diameter : 3.33"
Length : 4.83'
Weight : 141 lbs
Series : 4993EA
Mnemonic : HVRT

HRVTM 7.0 - 9.625" UPPER MODULE

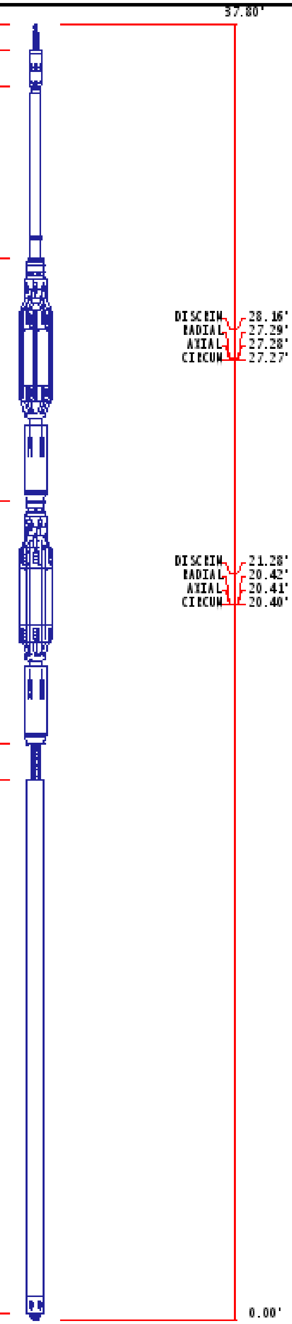
Diameter : 5.50"
Length : 6.83'
Weight : 332 lbs
Series : 4997PA
Mnemonic : HVRT
Measure Point: 4.92' : DISCRIM
Measure Point: 4.05' : RADIAL
Measure Point: 4.04' : AXIAL
Measure Point: 4.03' : CIRCUM

HRVTM 7.0 - 9.625" LOWER MODULE

Diameter : 5.50"
Length : 6.85'
Weight : 335 lbs
Series : 49970A
Mnemonic : HVRT
Measure Point: 4.89' : DISCRIM
Measure Point: 4.03' : RADIAL
Measure Point: 4.02' : AXIAL
Measure Point: 4.01' : CIRCUM

KNUCKLE JOINT

Diameter : 2.88"



SINKER BAR 3.13" - STEEL

Diameter : 3.38"
Length : 15.21'
Weight : 180 lbs
Series : 3914NA
Mnemonic : SNKB

BULL PLUG 3.38"

TOTAL LENGTH: 37.80'
TOTAL WEIGHT: 1077 lbs
MAX DIAMETER: 0'5.50"

120	3717.27	3748.78	31.51	Class 4	86.0%	3734.99	OD
121	3748.78	3780.85	32.07	Class 2	37.0%	3769.98	OD
122	3780.85	3812.51	31.66	Class 1	-	-	-
123	3812.51	3842.32	29.81	Class 2	35.0%	3831.18	OD
124	3842.32	3872.46	30.14	Class 1	-	-	-
125	3872.46	3903.25	30.79	Class 1	-	-	-
126	3903.25	3934.20	30.95	Class 2	21.0%	3933.02	OD
127	3934.20	3964.22	30.02	Class 2	27.0%	3936.23	OD
128	3964.22	3995.68	31.46	Class 2	25.0%	3983.94	OD
129	3995.68	4026.51	30.83	Class 2	34.0%	3998.32	OD
130	4026.51	4058.66	32.15	Class 1	-	-	-
131	4058.66	4089.46	30.80	Class 1	-	-	-
132	4089.46	4118.75	29.29	Class 1	-	-	-
133	4118.75	4150.33	31.58	Class 1	-	-	-
134	4150.33	4182.43	32.10	Class 2	25.0%	4151.22	OD
135	4182.43	4214.13	31.70	Class 2	27.0%	4183.00	OD
136	4214.13	4244.49	30.36	Class 4	91.0%	4225.45	OD
137	4244.49	4275.98	31.49	Class 1	-	-	-
138	4275.98	4307.03	31.05	Class 1	-	-	-
139	4307.03	4338.36	31.33	Class 2	36.0%	4307.96	OD
140	4338.36	4369.93	31.57	Class 1	-	-	-
141	4369.93	4399.55	29.62	Class 2	31.0%	4376.39	OD
142	4399.55	4431.63	32.08	Class 2	25.0%	4412.97	OD
143	4431.63	4462.94	31.31	Class 1	-	-	-
144	4462.94	4492.40	29.46	Class 3	49.0%	4463.44	OD
145	4492.40	4524.61	32.21	Class 4	70.0%	4493.28	OD
146	4524.61	4555.95	31.34	Class 1	-	-	-
147	4555.95	4576.27	20.32	Class 1	-	-	-

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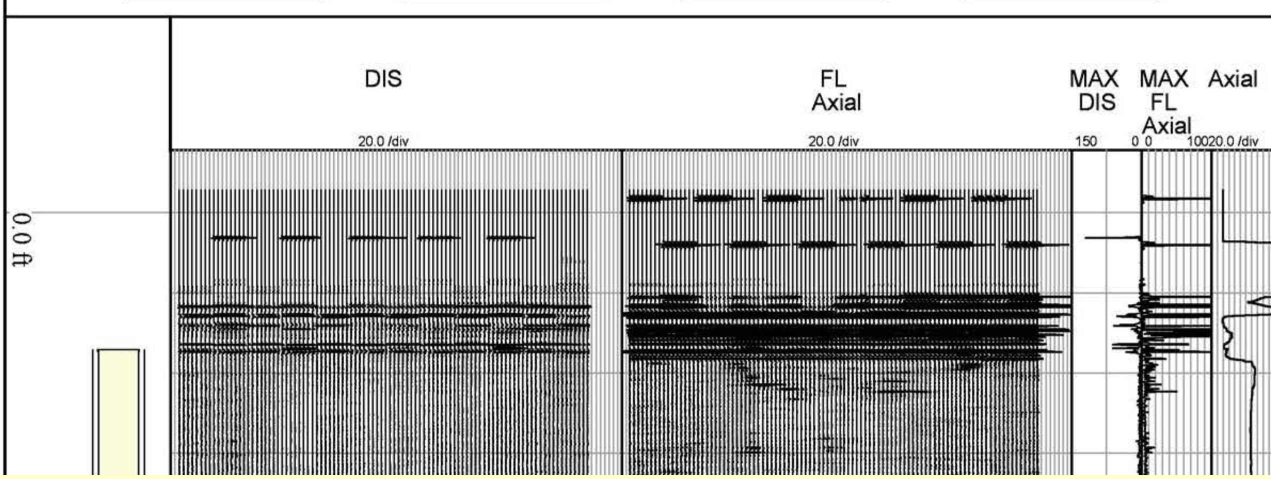
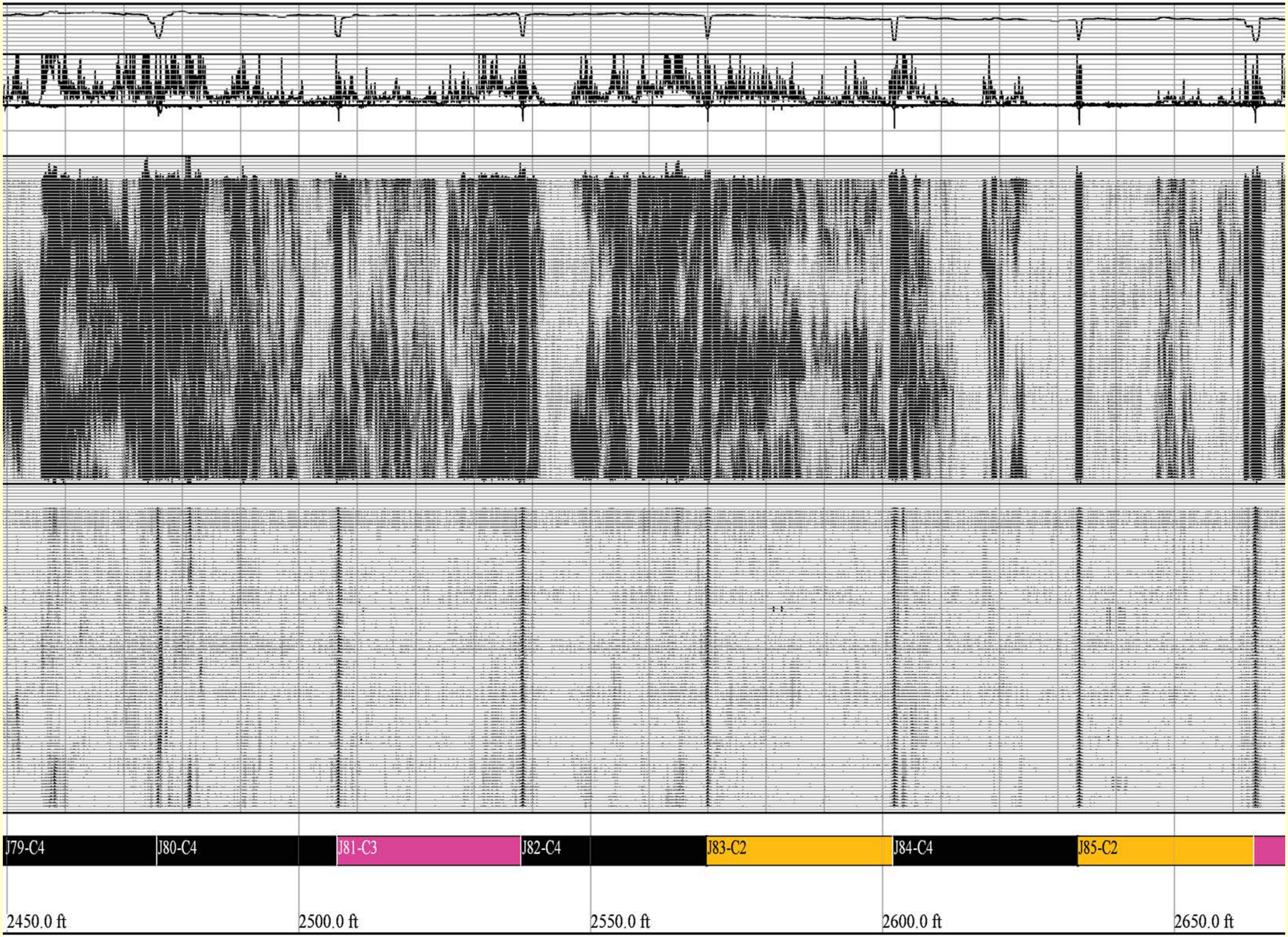
Main Section
5in / 100ft - Scale

Class 1	Class 2	Class 3	Class 4
0 - 20%	20 - 40%	40 - 60%	60 - 100%




J79-C4
J80-C4
J81-C3
J82-C4
J83-C2
J84-C4
J85-C2
2450.0 ft
2500.0 ft
2550.0 ft
2600.0 ft
2650.0 ft

CASING INSPECTION LOG

CALIPER LOG

JOINT ANALYSIS REPORT WITH PIPE GRADE

PIONEER

Company:
Well:
Field: N
County:
State: TEXAS
Date: 9/23/2018

	9.625" - 47#			Other WT	GRADE
	0.0%	15.0%		0% to 15%	A
	15.0%	30.0%		15.1% to 30%	B
	30.0%	50.0%		30.1% to 50%	C
		50.0%		> 50.1%	F

Comment:

Joint No.	Depth Feet	Length Feet	Max Pen %	Max Pen Depth	Max ID Inches	Min Wall Inches	Nominal ID Inches	Weight lb/ft	Pipe Grade	Theoretical Burst Press	Comment
113	4957.22	44.12	14.5%	4988.30	8.818	0.404	8.681		A		
114	5002.34	43.27	11.5%	5005.07	8.790	0.418	8.681		A		
115	5046.62	44.28	12.6%	5048.55	8.800	0.412	8.681		A		
116	5091.90	43.90	12.3%	5134.69	8.797	0.414	8.681		A		
117	5136.80	44.90	13.1%	5166.99	8.805	0.410	8.681		A		
118	5182.70	46.15	15.5%	5182.69	8.827	0.399	8.681		B		
119	5229.85	43.67	14.9%	5261.47	8.822	0.402	8.681		A		
120	5274.52	44.20	15.0%	5309.10	8.823	0.401	8.681		B		
121	5319.71	44.69	10.2%	5351.12	8.777	0.424	8.681		A		
122	5365.40	43.10	12.8%	5401.94	8.802	0.411	8.681		A		
123	5409.50	43.35	12.8%	5427.32	8.802	0.411	8.681		A		
124	5453.85	33.73	13.1%	5454.34	8.805	0.410	8.681		A		
125	5488.58	46.18	12.8%	5499.85	8.802	0.411	8.681		A		
126	5535.75	44.12	15.4%	5559.70	8.826	0.399	8.681		B		
127	5580.88	44.25	16.8%	5590.40	8.840	0.392	8.681		B		
128	5626.12	43.88	13.7%	5664.59	8.810	0.407	8.681		A		
129	5671.00	42.93	10.6%	5702.37	8.781	0.422	8.681		A		
130	5714.92	44.31	15.8%	5751.77	8.830	0.398	8.681		B		
131	5760.23	43.09	14.2%	5801.64	8.815	0.405	8.681		A		
132	5804.32	46.09	11.2%	5825.69	8.787	0.419	8.681		A		
133	5851.41	43.63	11.1%	5892.57	8.786	0.419	8.681		A		
134	5896.04	43.61	14.9%	5899.09	8.822	0.402	8.681		A		
135	5940.64	43.73	12.2%	5959.35	8.796	0.415	8.681		A		
136	5985.37	45.05	16.6%	6014.52	8.838	0.393	8.681		B		
137	6031.42	43.16	14.2%	6044.40	8.815	0.405	8.681		A		
138	6075.58	41.89	14.9%	6076.39	8.822	0.402	8.681		A		
139	6118.47	44.44	17.2%	6140.34	8.843	0.391	8.681		B		
140	6163.91	44.98	18.5%	6203.24	8.856	0.385	8.681		B		
141	6211.37	42.89	18.4%	6245.07	8.855	0.385	8.681		B		DV Tool 6208' - 6211'
142	6255.25	8.42	15.3%	6259.62	8.825	0.400	8.681		B		
143	6264.67	11.15	13.6%	6269.25	8.809	0.408	8.681		A		
144	6276.82	15.56	14.9%	6281.57	8.822	0.402	8.681		A		
145	6293.38	14.66	12.6%	6307.64	8.800	0.412	8.681		A		
146	6309.04	15.53	12.0%	6313.95	8.794	0.416	8.681		A		
147	6325.58	13.92	13.9%	6336.62	8.812	0.406	8.681		A		
148	6340.50	15.49	17.4%	6341.59	8.845	0.390	8.681		B		
149	6356.98	13.82	12.2%	6367.69	8.796	0.415	8.681		A		
150	6371.81	15.45	14.0%	6375.14	8.813	0.406	8.681		A		
151	6388.26	14.03	13.8%	6401.94	8.811	0.407	8.681		A		
152	6403.29	15.40	14.7%	6407.20	8.820	0.403	8.681		A		
153	6419.69	15.40	13.3%	6433.27	8.807	0.409	8.681		A		
154	6436.09	7.84	16.1%	6442.52	8.833	0.396	8.681		B		

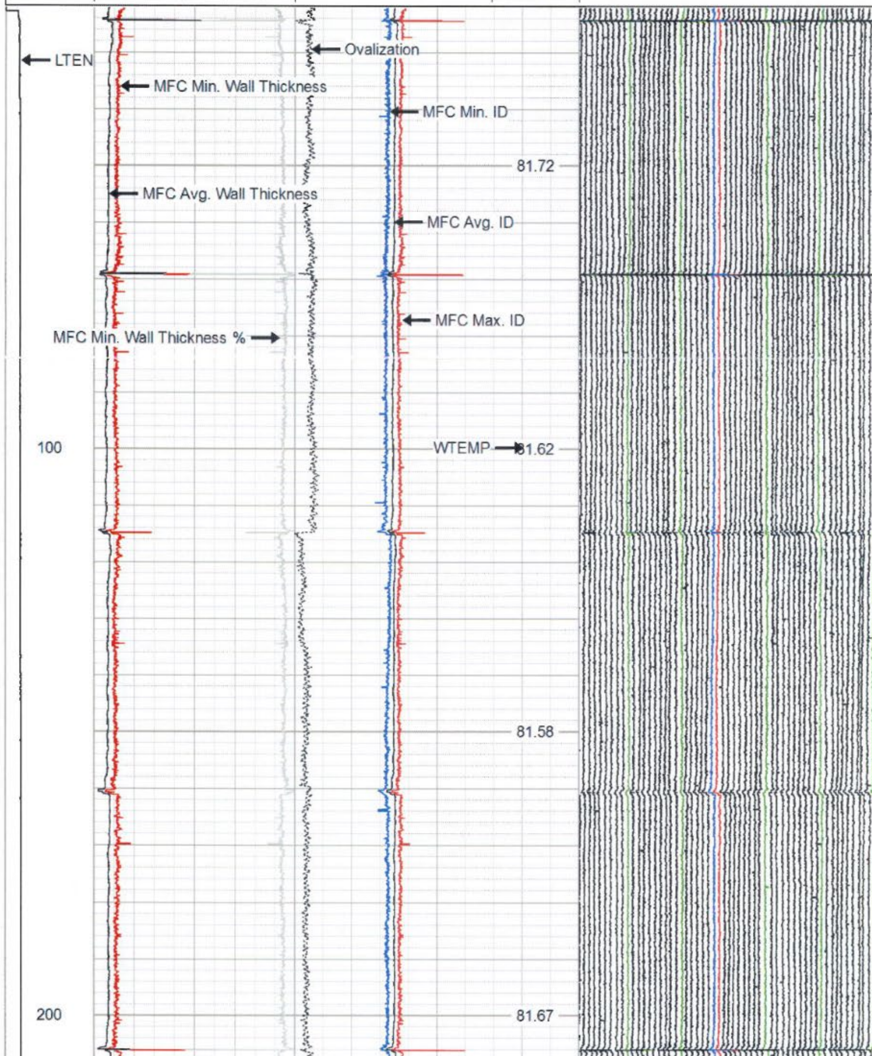
PIONEER

9.625" - 47# CASING
8.681" ID / .472" WALL

Database File	_mipd.db
Dataset Pathname	
Presentation Format	dc_mfc_56arm_8-10in_3in_p1
Dataset Creation	Tue Sep 25 09:58:06 2018
Charted by	Depth in Feet scaled 1:240

LTEN	MFC Min. Wall Thickness	MFC Min. ID (in)	56 RADII 0.0536 INC. 3" SCALE FINGER 01
0 (lb 2000	0.5 (in) 0	8 MFC Avg. ID (in) 10	
	MFC Min. Wall Thickness	8 MFC Max. ID (in) 10	FINGER 56
	0 100	0 Ovalization (in) 0.5	
	MFC Avg. Wall Thickness	WTEMP	
	0.5 (in) 0	(degF)	

Scale: MFC Min. ID (in) 8 – 10



A GOOD MANUAL TO HAVE ON HAND

EPA/600/R-94/124
July 1994

Temperature, Radioactive Tracer, and Noise Logging for Injection Well Integrity

by

R. M. McKinley
Exxon Production Research

Cooperative Agreement No. CR-818926

Project Officer

Jerry T. Thornhill
Extramural Activities and Assistance Division
Robert S. Kerr Environmental Research Laboratory
Ada, Oklahoma 74820

ROBERT S. KERR ENVIRONMENTAL RESEARCH LABORATORY
OFFICE OF RESEARCH AND DEVELOPMENT
U.S. ENVIRONMENTAL PROTECTION AGENCY
ADA, OKLAHOMA 74820

RADIOACTIVE TRACER SURVEYS

(RATS or RTS)

RADIOACTIVE TRACER SURVEY PURPOSE

- FLOW PROFILING (volumetric)
- DETERMINE FLUID MIGRATION
  - BOTTOMHOLE CEMENT CHANNELS (Time Drive)
  - CASING, TUBING, PACKER LEAKS (Internal MI)(Slug Chase)

RATS
OPERATION PRINCIPLES

- **USE RADIOACTIVE IODINE (1/2 life = 8 days)**
- **EJECT TRACER @ surface or downhole**
- **FOLLOW TRACER as it travels**
- **USE GAMMA RAY TOOL as detector**
- **DETECT MIGRATION OF TRACER through tubing and/or casing**

RATS EQUIPMENT

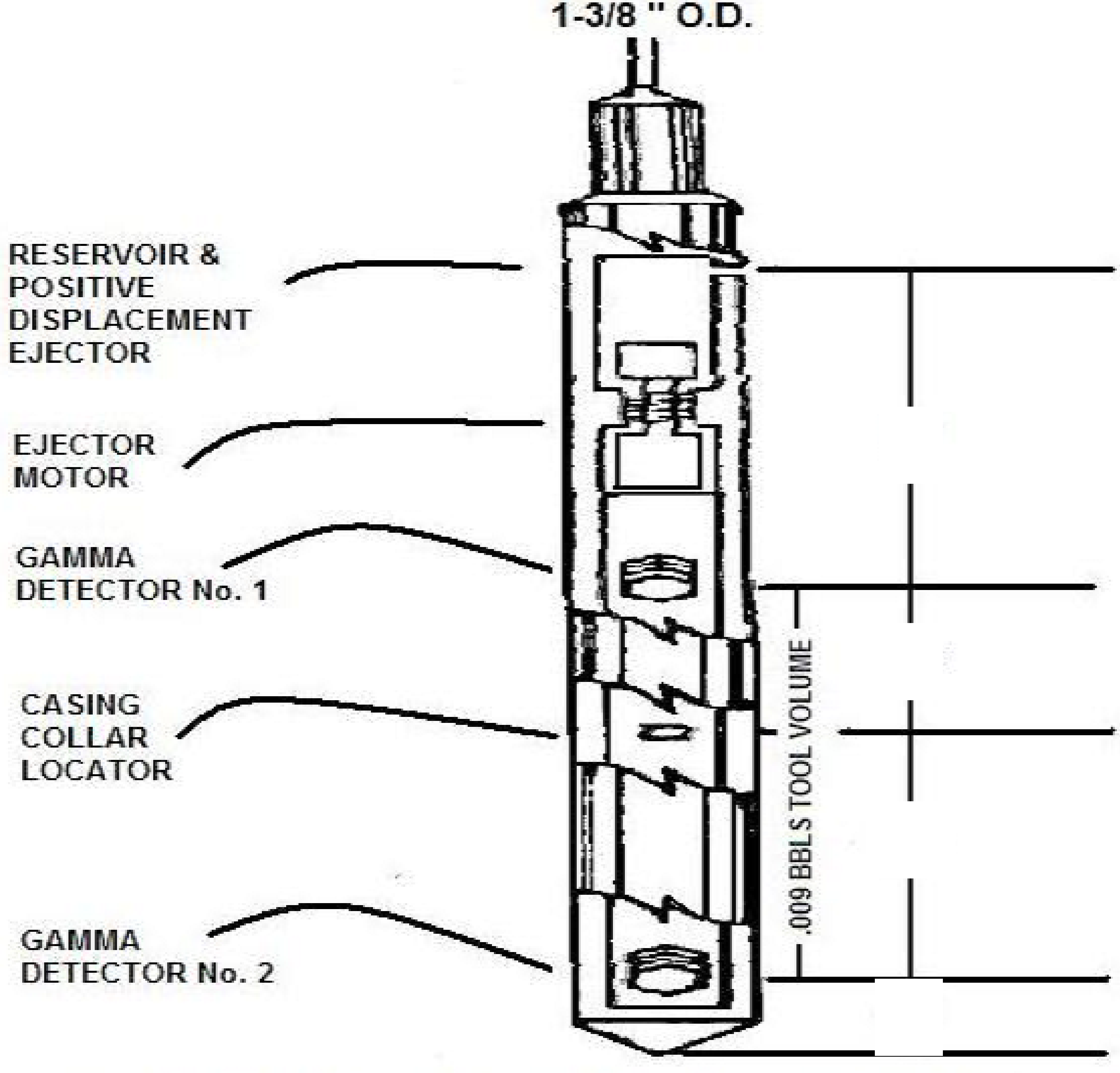
- **Radioactive material EJECTOR**
  Surface or downhole
- **2 or more Gamma Ray DETECTORS**
- **Ejector/Detector CONFIGURATION varies depending on objective**
- **Tool DIAMETER as small as 1-1/2 inches**

RATS PROCEDURE

- **LOAD TRACER** at surface
- **RUN** tool in tubing or casing
- **RUN BASE LOG** with well on injection
- **EJECT** tracer at or near surface if running in casing
- **EJECT** tracer above the packer if in tubing
- **FOLLOW** tracer to injection zone, while checking for leaks
- **LOG ABOVE PERFORATIONS/SCREEN** for channels outside casing
- Can check **FLOW PROFILE** with Spinner
- Run with **CASING COLLAR LOCATOR**

FACTORS AFFECTING GAMMA-RAY MEASUREMENT

- RADIOACTIVE (HOT) formations
- INJECTION RATE
- Ejector/Detector CONFIGURATION
- PIPE SCALE



SCHEMATIC OF RADIOACTIVE TRACER FOR INJECTION LOGGING

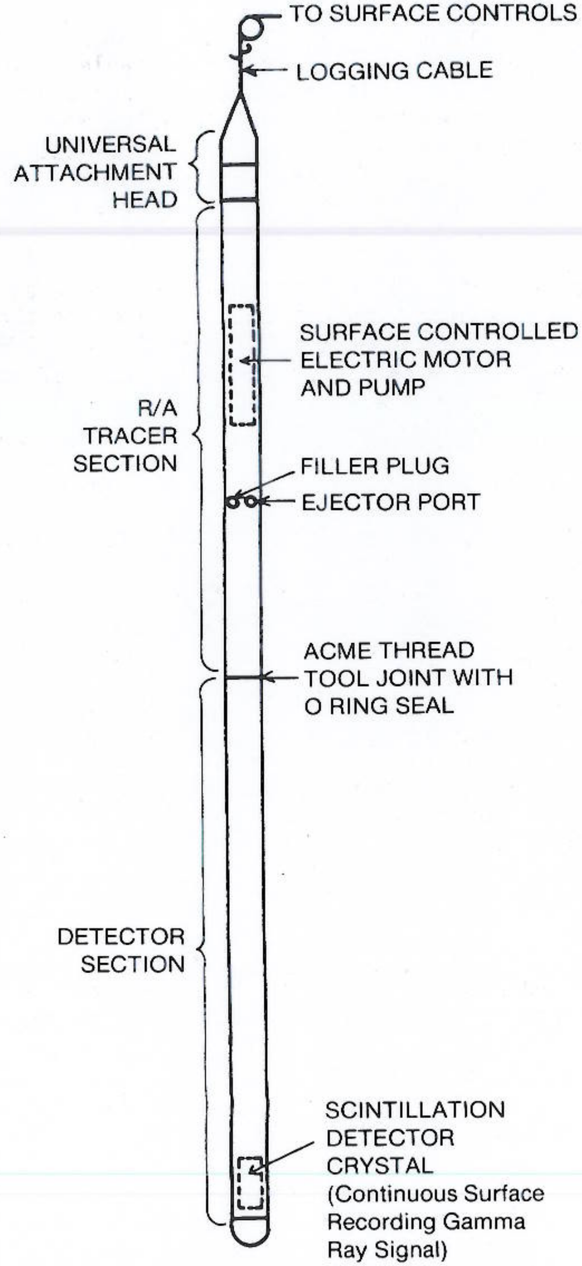


Figure 73. Radioactive tracer tool (Ford, 1962).

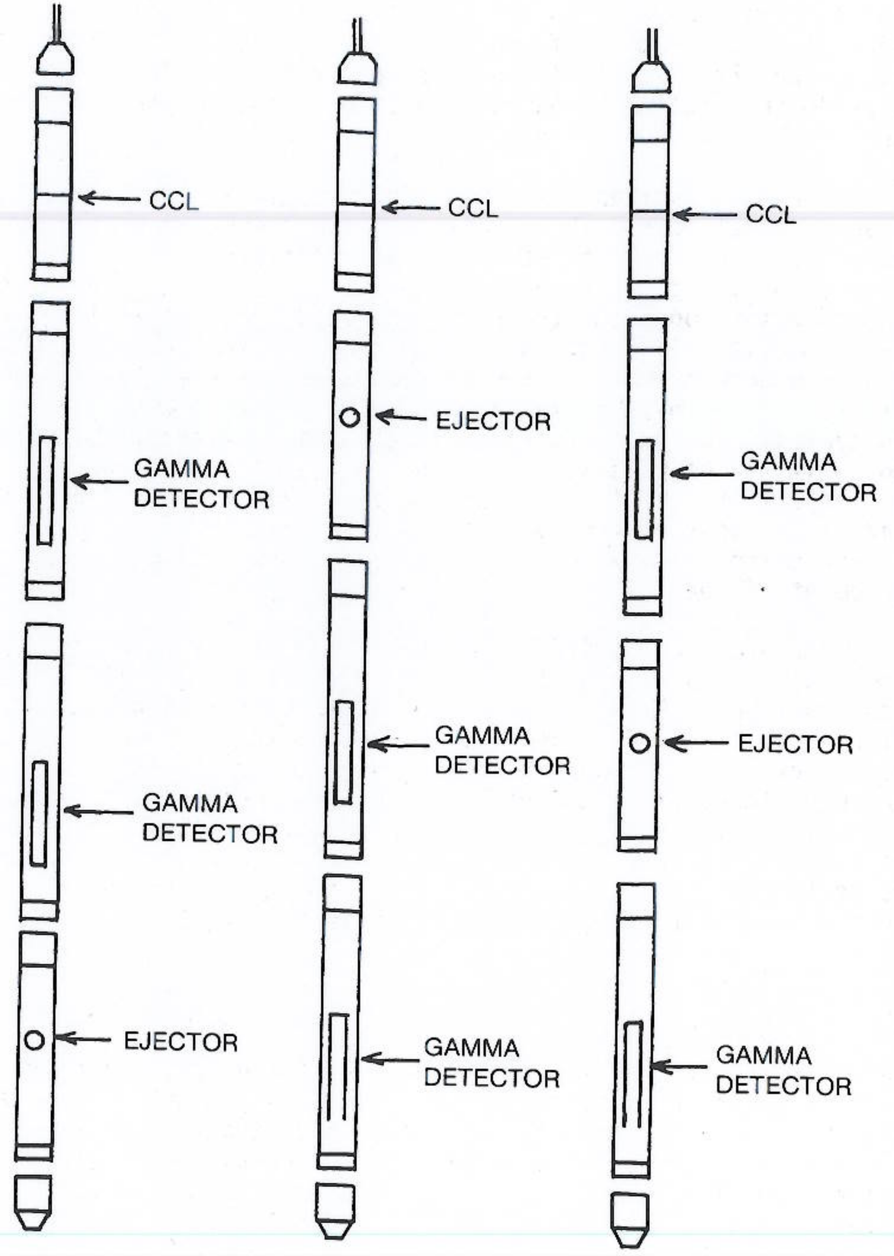
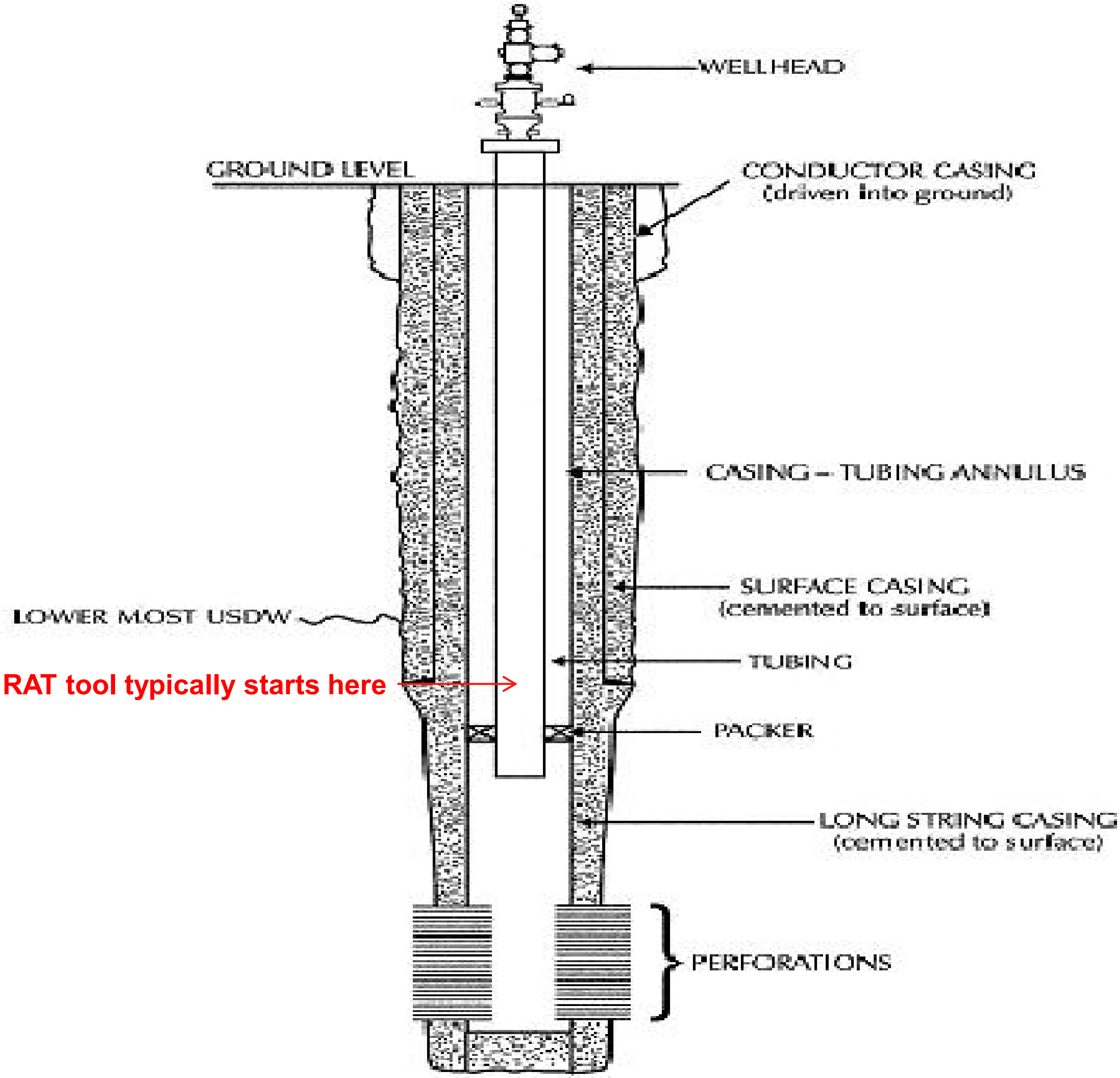


Figure 74. Three possible configurations of a radioactive tracer tool (courtesy Schlumberger) (Dewan, 1982).

Slug
Chase
(Internal MI)


WELLHEAD
GROUND LEVEL
CONDUCTOR CASING
(driven into ground)
CASING – TUBING ANNULUS
SURFACE CASING
(cemented to surface)
LOWER MOST USDW
TUBING
RAT tool typically starts here
PACKER
LONG STRING CASING
(cemented to surface)
PERFORATIONS

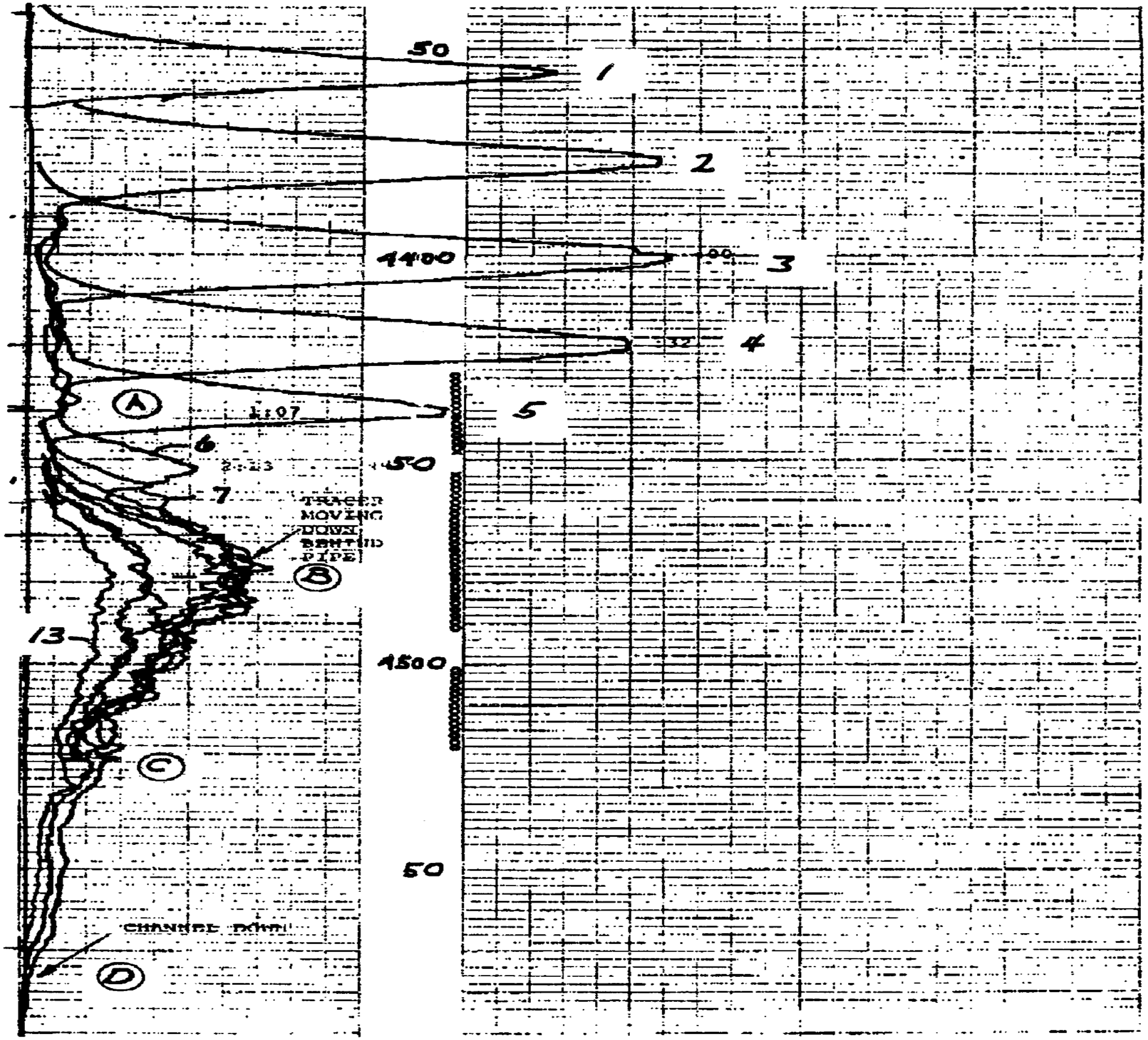


Figure 41. Slug-tracking survey from well on injection at 950 BPD

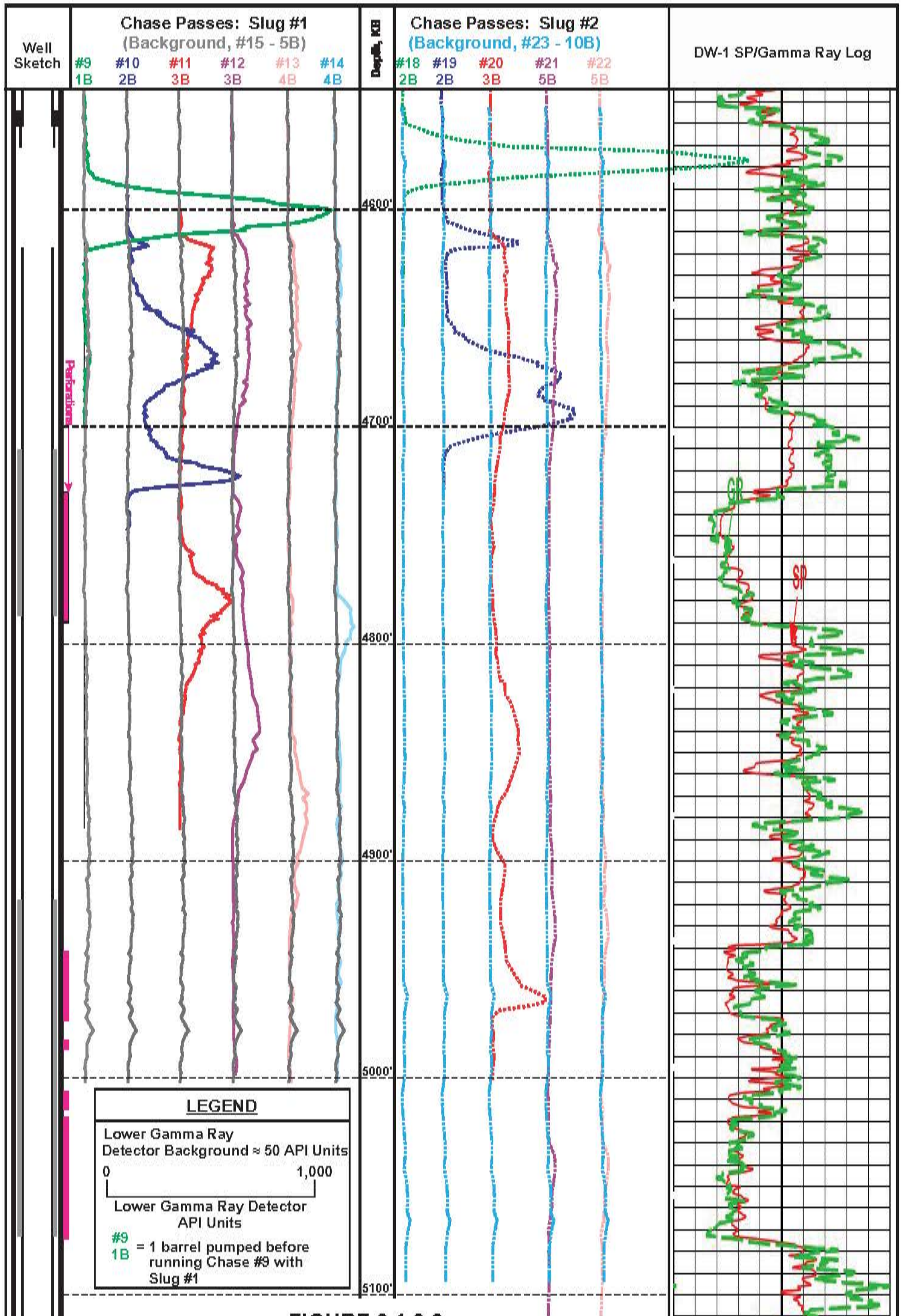
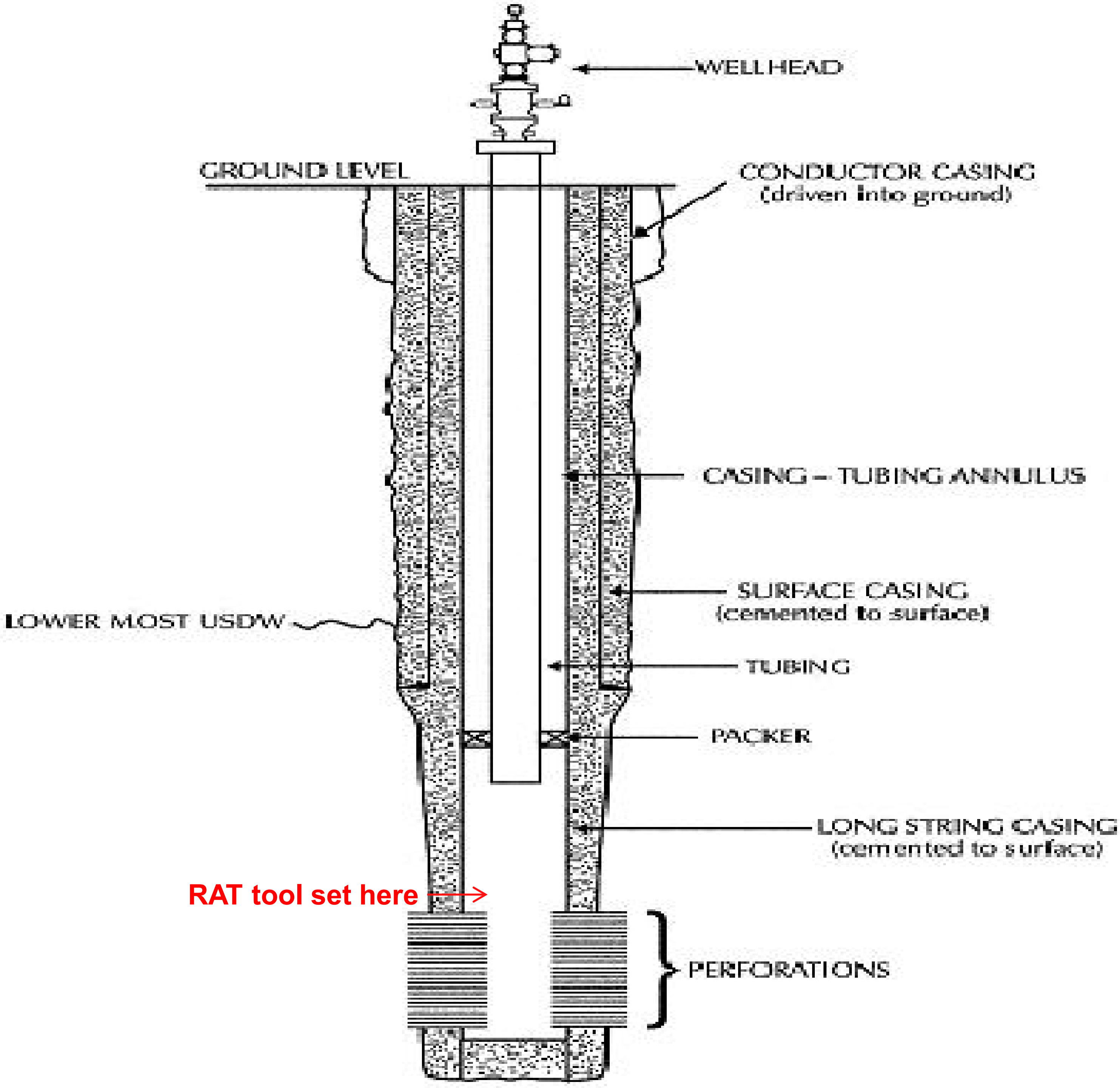

Well Sketch
Chase Passes: Slug #1
(Background, #15 - 5B)
#9 1B
#10 2B
#11 3B
#12 3B
#13 4B
#14 4B
Depth, KB
Chase Passes: Slug #2
(Background, #23 - 10B)
#18 2B
#19 2B
#20 3B
#21 5B
#22 5B
DW-1 SP/Gamma Ray Log
Perforations
4600'
4700'
4800'
4900'
5000'
5100'
GR
SP
LEGEND
Lower Gamma Ray Detector Background ≈ 50 API Units
0
1,000
Lower Gamma Ray Detector API Units
#9 1B = 1 barrel pumped before running Chase #9 with Slug #1

FIGURE 3.1.3.2

TIME
DRIVES
(Test Bottomhole Cement)



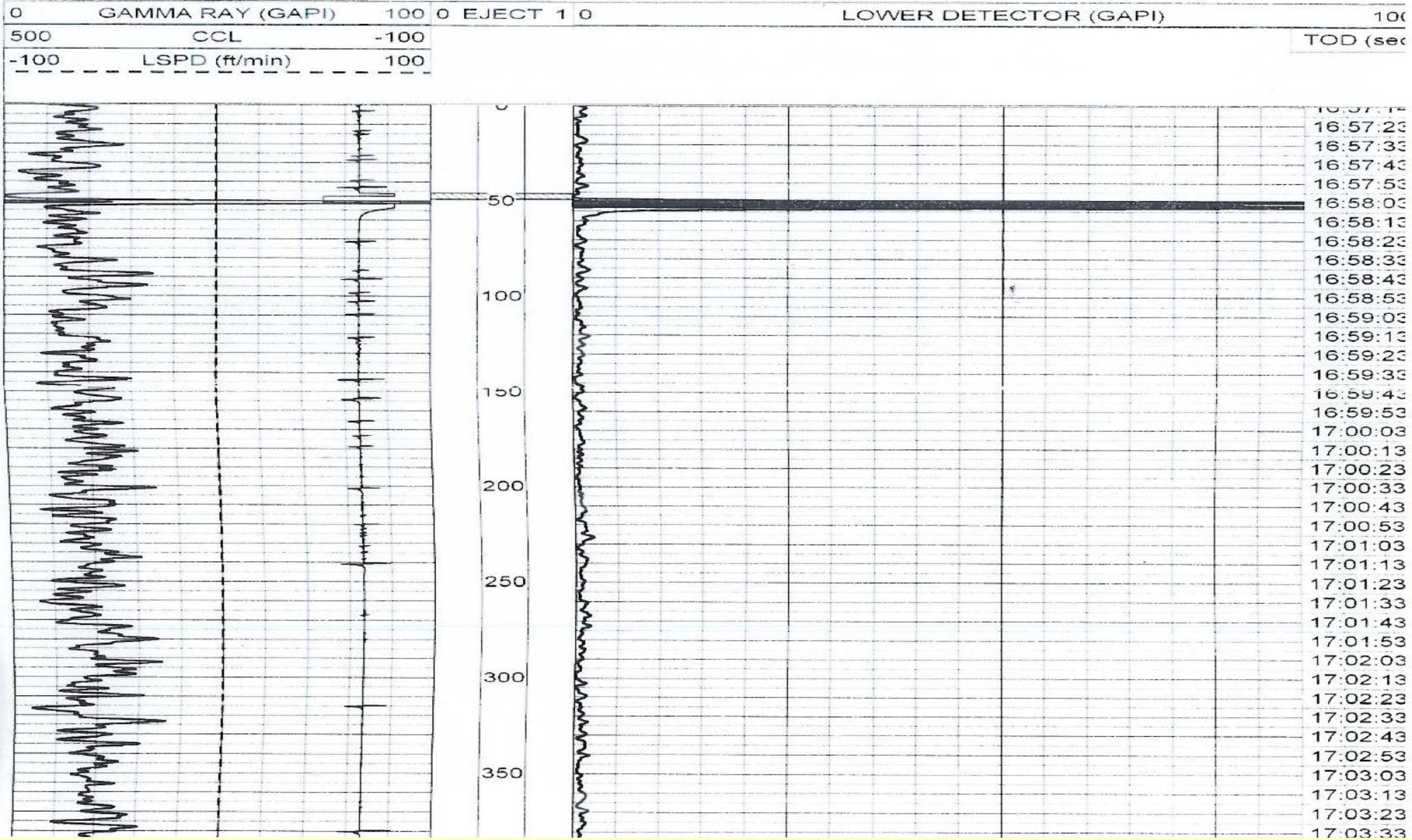
WELLHEAD
GROUND LEVEL
CONDUCTOR CASING
(driven into ground)
CASING – TUBING ANNULUS
SURFACE CASING
(cemented to surface)
LOWER MOST USDW
TUBING
PACKER
LONG STRING CASING
(cemented to surface)
RAT tool set here
PERFORATIONS

Gulf Coast
Well Analysis

TIME DRIVE # 2 EJECTED AT 7395' AT 16:58

UPPER DETECTOR AT 7392' LOWER DETECTOR AT 7400'
INJECTION RATE 200 GPM AT 180 PSI

Database File:	[redacted]
Dataset Pathname:	pass20
Presentation Format:	tracer
Dataset Creation:	Fri Jul 13 16:57:14 2012 by Log PIP Casedhole Loggi
Charted by:	Time scaled 72"/hour

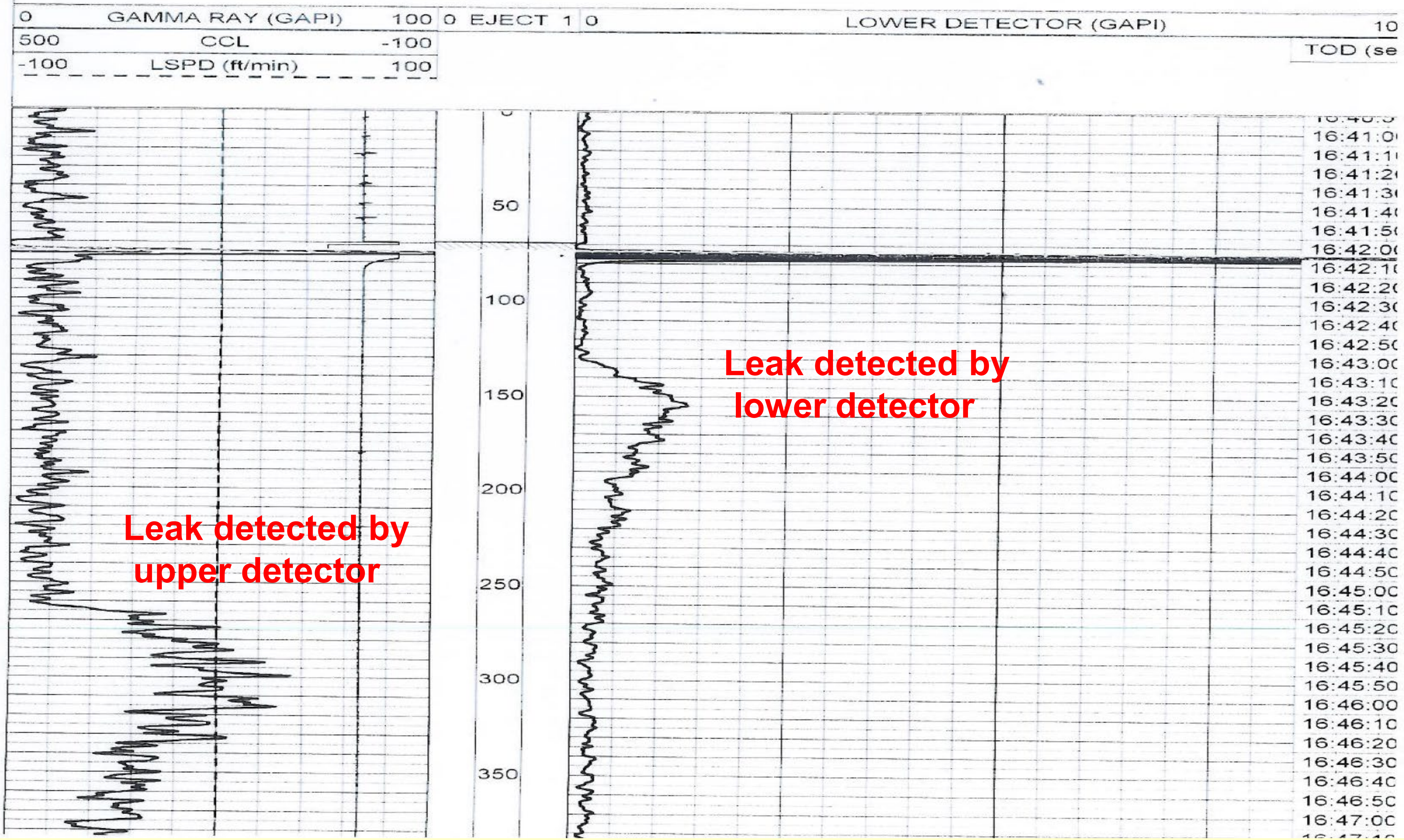


Gulf Coast
Well Analysis

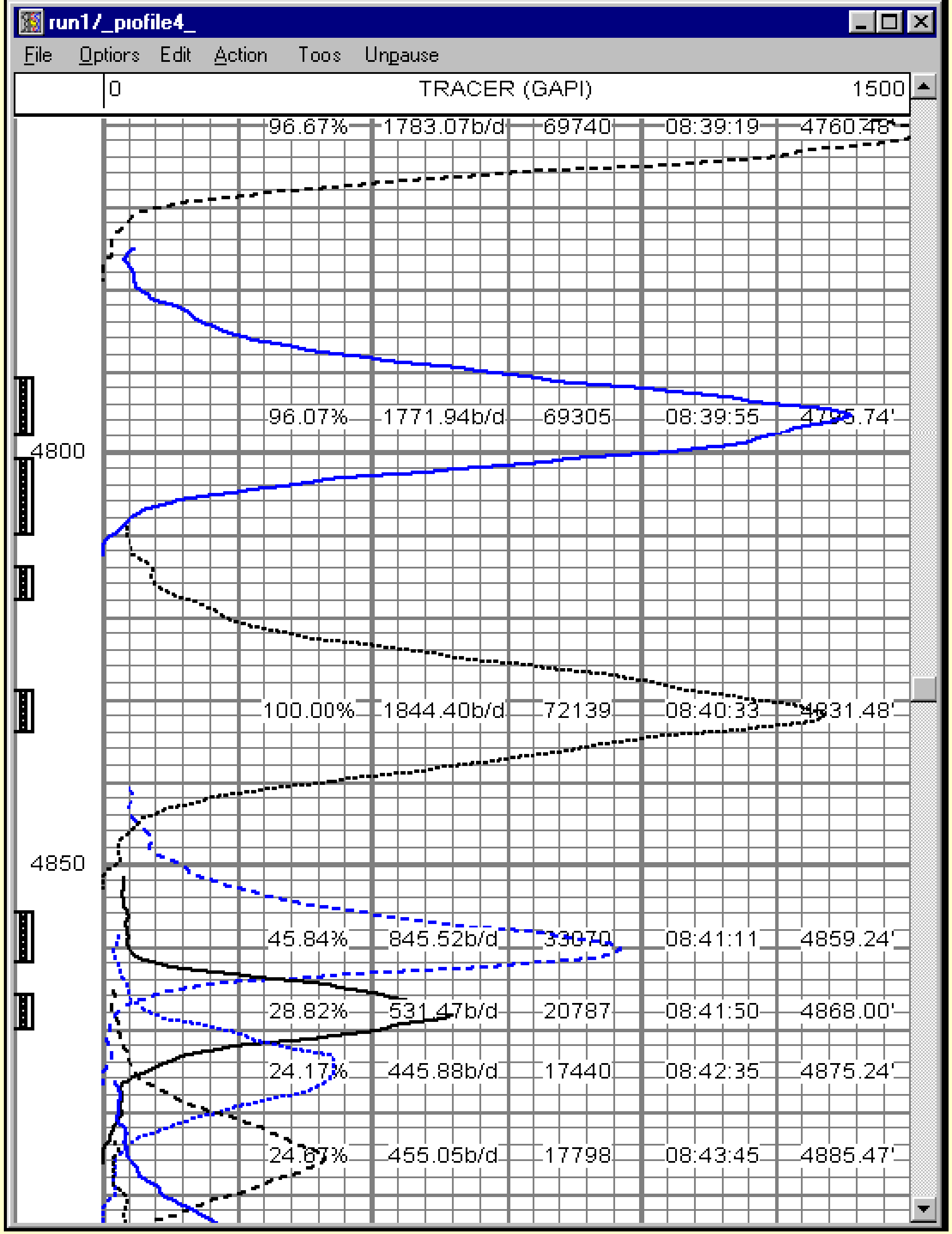
TIME DRIVE # 1 EJECTED AT 7435' AT 16:42

UPPER DETECTOR AT 7432' LOWER DETECTOR AT 7440'
INJECTION RATE 200 GPM AT 100 PSI

Database File:	[redacted]
Dataset Pathname:	pass18
Presentation Format:	tracer
Dataset Creation:	Fri Jul 13 16:40:50 2012 by Log PIP Casedhole Loggi
Charted by:	Time scaled 72"/hour



Flow Profiles

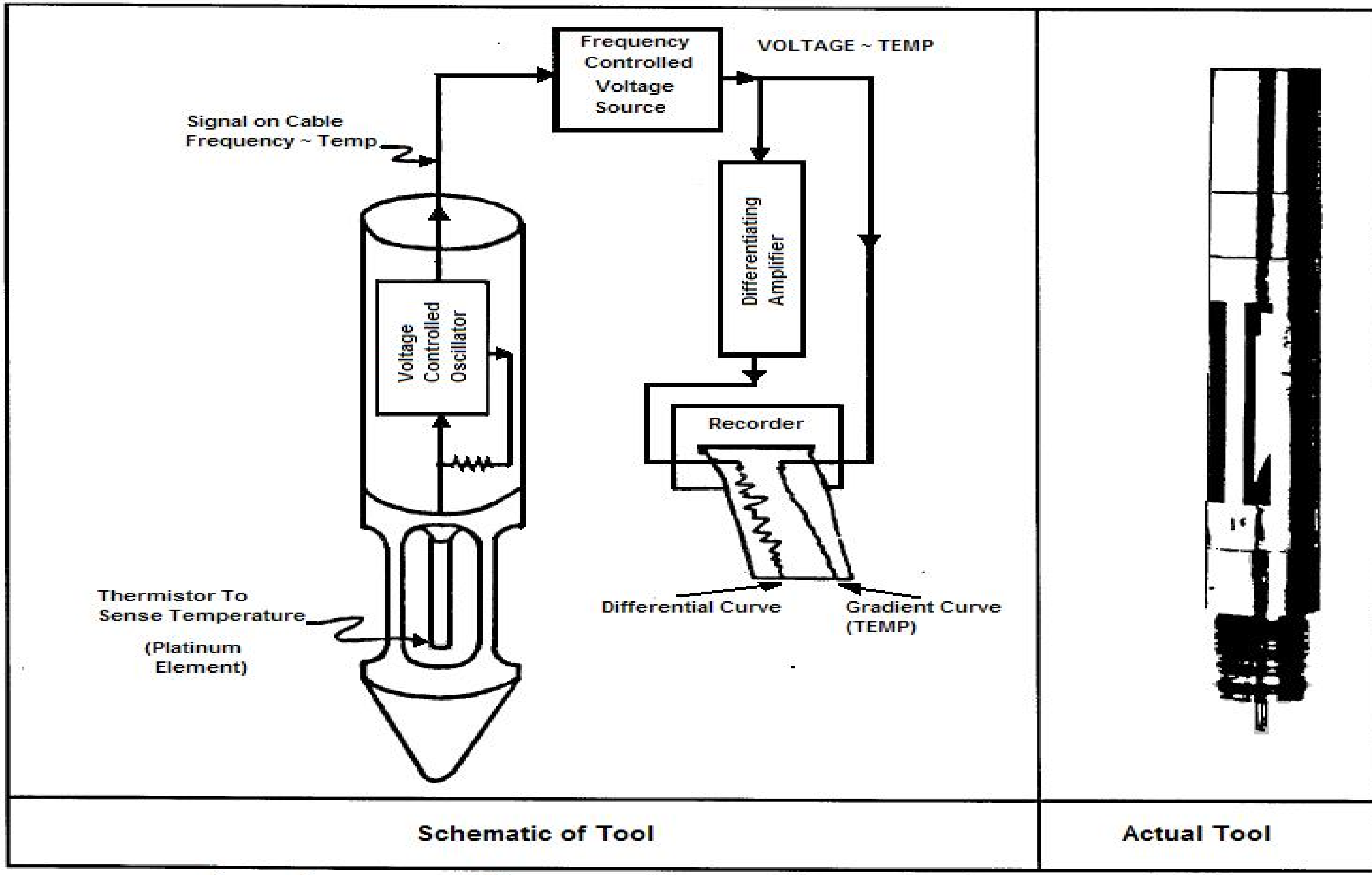


TEMPERATURE SURVEYS

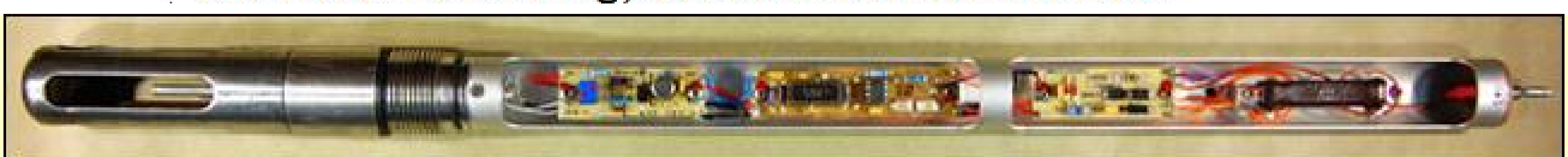
(External MI)

TEMPERATURE SURVEYS

- Oldest of the Production Surveying Instruments (mid 1930s)
    - Mercury/piston
    - Vapor pressure/bourdon type element (Bottomhole temperature measurements)
    - Thermistor – platinum element – resolves temperature changes of 0.05 deg F
        - » **Analog Logging Units**
        - » **Digital Logging Units**



A surface recording, continuous thermometer



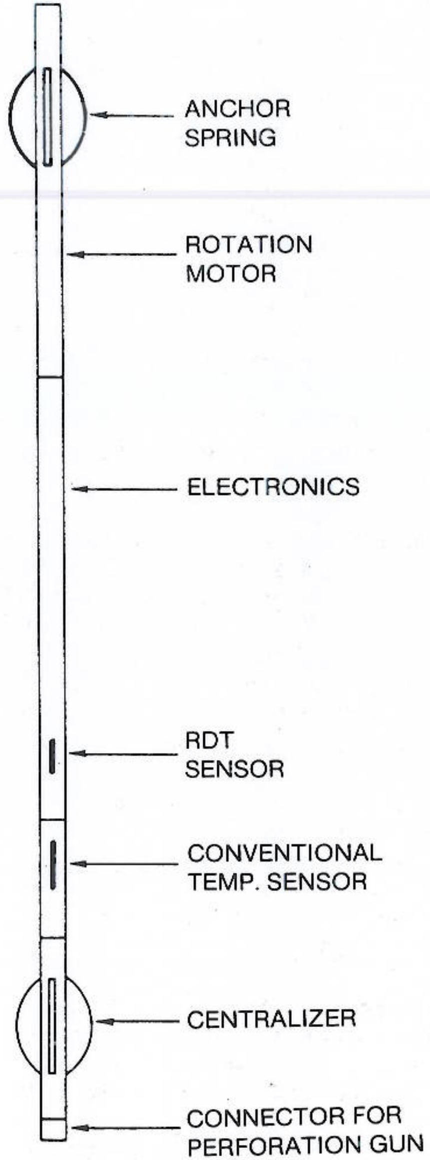


Figure 16. Schematic of RDT logging tool (Cooke, 1978).

TEMPERATURE SURVEY PURPOSE

- LOCATE **CEMENT TOPS** AFTER PRIMARY CEMENTING (HEAT FROM EXOTHERMIC REACTION)

- **FLUID MIGRATION** DETERMINATION
  - CASING SHOE BEHIND PIPE
  - TUBING, CASING, PACKER LEAKS
  - INTERFORMATIONAL FLUID FLOW

- **FLOW** (VOLUMETRIC) **PROFILING** (RARE)

- **IDENTIFICATION OF** INTERVALS PRODUCING **GAS** (COOLING EFFECT FROM EXPANSION)

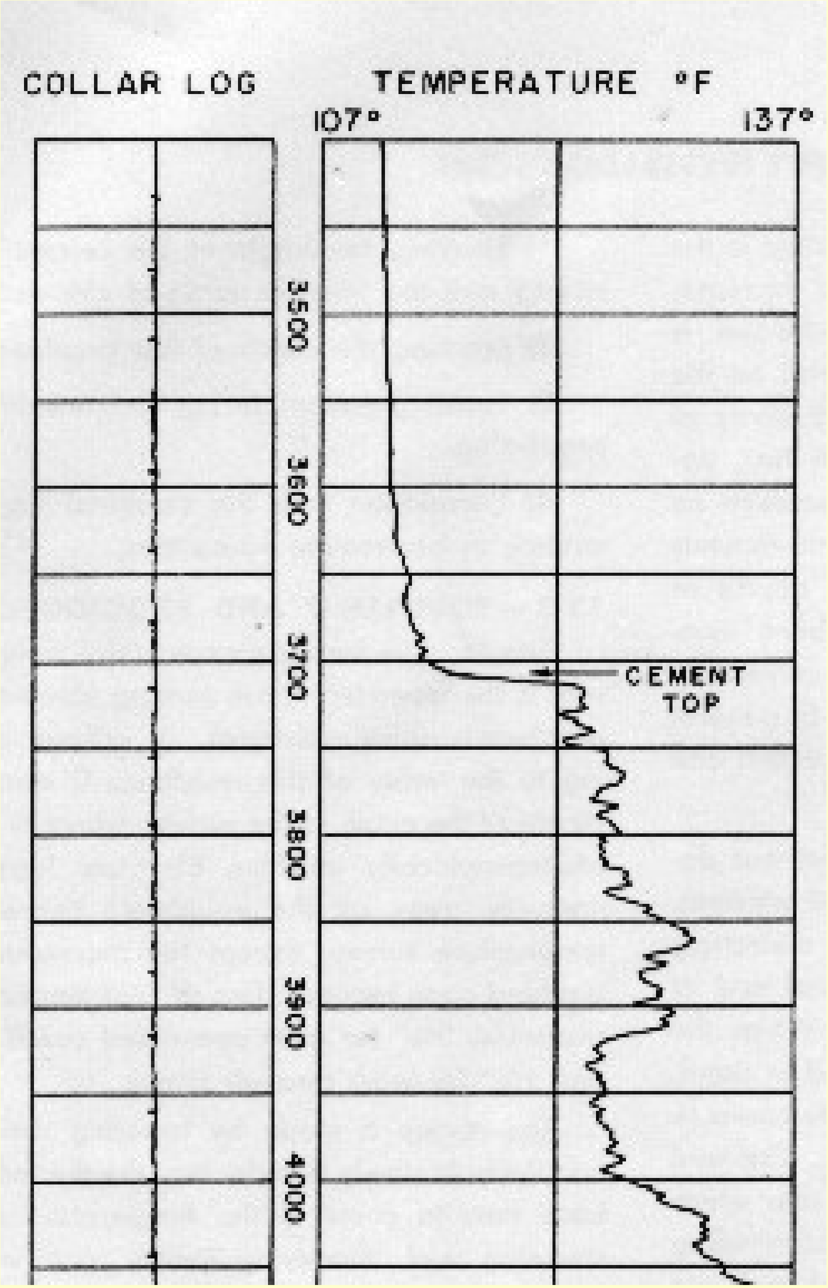
TEMPERATURE SURVEY OPERATION PRINCIPLE

- DOWNHOLE TEMPERATURE GOVERNED BY **GEOTHERMAL GRADIENT**
- INJECTION OF FLUID WITH LARGE **TEMPERATURE DIFFERENCE** (FROM GRADIENT)
- **ZONES** (OR LEAKS) TAKING INJECTED FLUIDS WILL **RETURN** TO GEOTHERMAL GRADIENT AT A **SLOWER RATE**

- Since cement gives off heat as it cures, the temperature log was used to provide evidence that the well was actually cemented to a level that met expectations. An example is shown at right.

- The top of cement is located where the temperature returns to geothermal gradient.

- The log must be run during the cement curing period as the temperature anomaly will fade with time.



TEMP SURVEY – A BASIC PROCEDURE

- LET WELL **STAND IDLE** AT LEAST 24 HOURS
- RUN **“BASE LOG”** – GEOTHERMAL GRADIENT
- ENSURE INJECTION FLUID **TEMPERATURE IS SIGNIFICANTLY DIFFERENT** FROM BOTTOM-HOLE TEMPERATURE
- START **INJECTION WHILE LOGGING** HOLE (OPTIONAL)
- **SHUT-IN** AFTER PREDETERMINED VOLUME IS INJECTED
- LOG HOLE **AFTER 0, 12, AND 24 HOURS** SHUT-IN

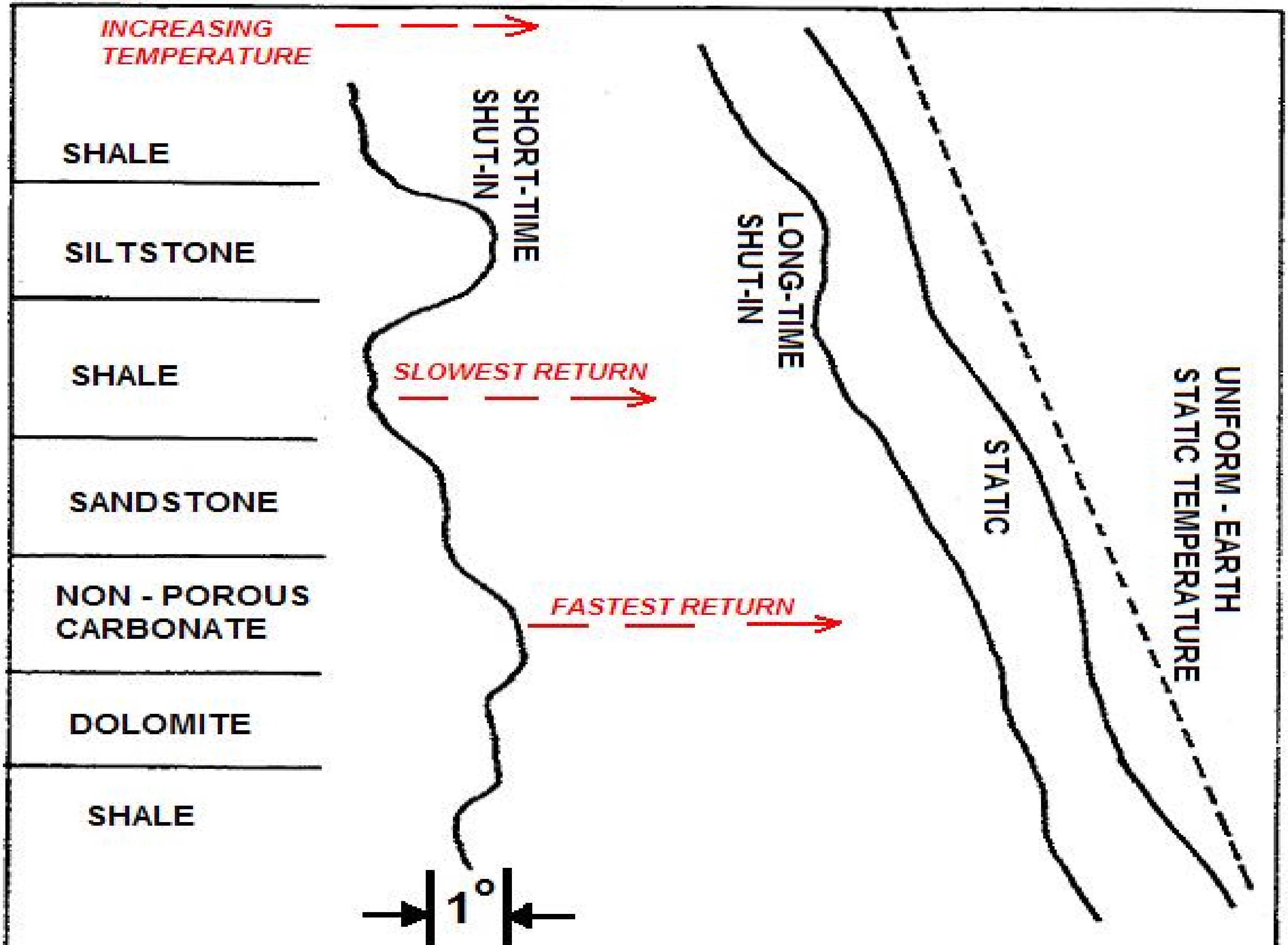


Figure 8 Hypothetical Influence of lithology on wellbore temperature warming with time to static conditions

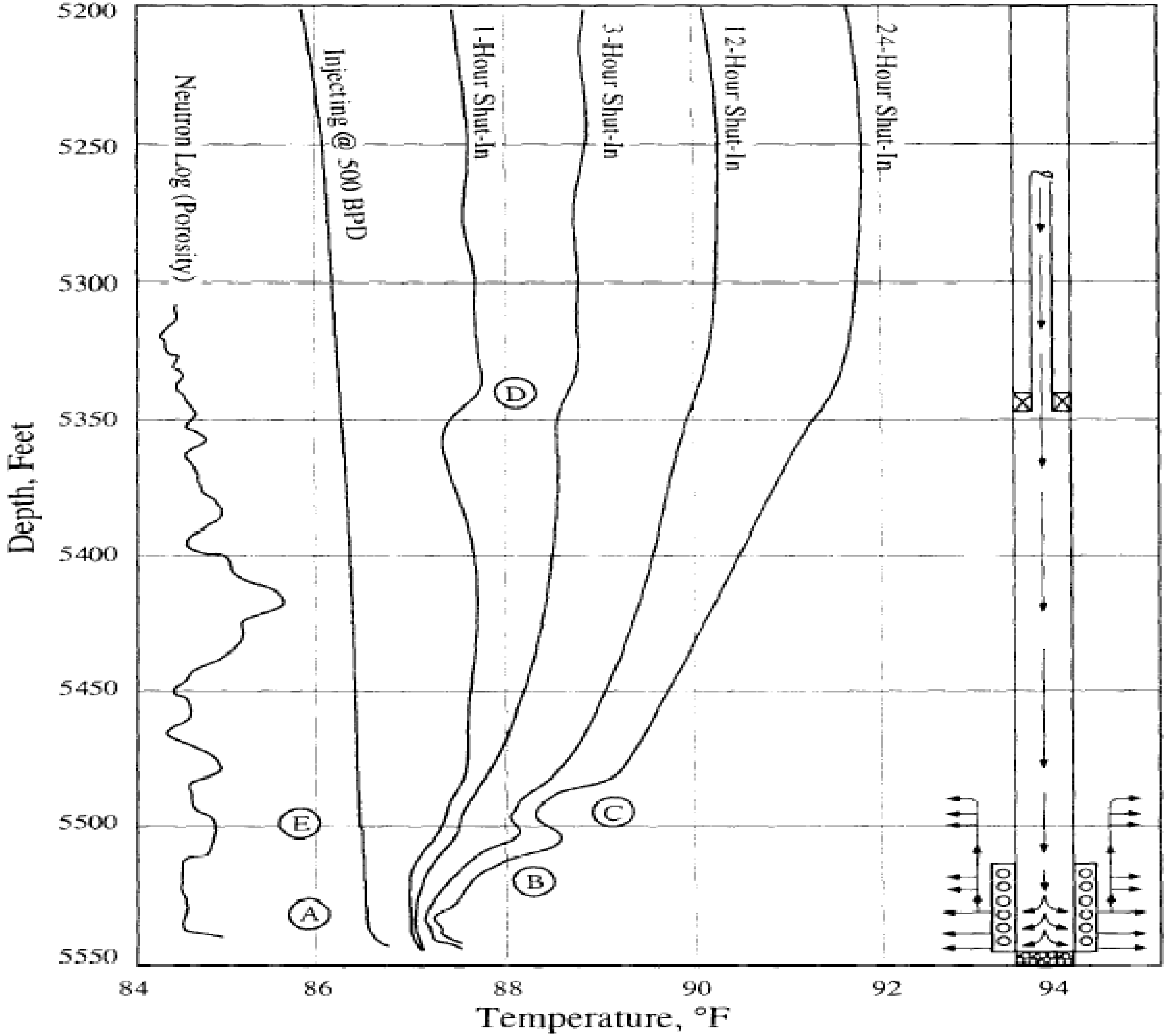


Figure 20. **Injecting and shut-in temperature surveys from well on continuous injection at about 500 BPD for almost one year.**

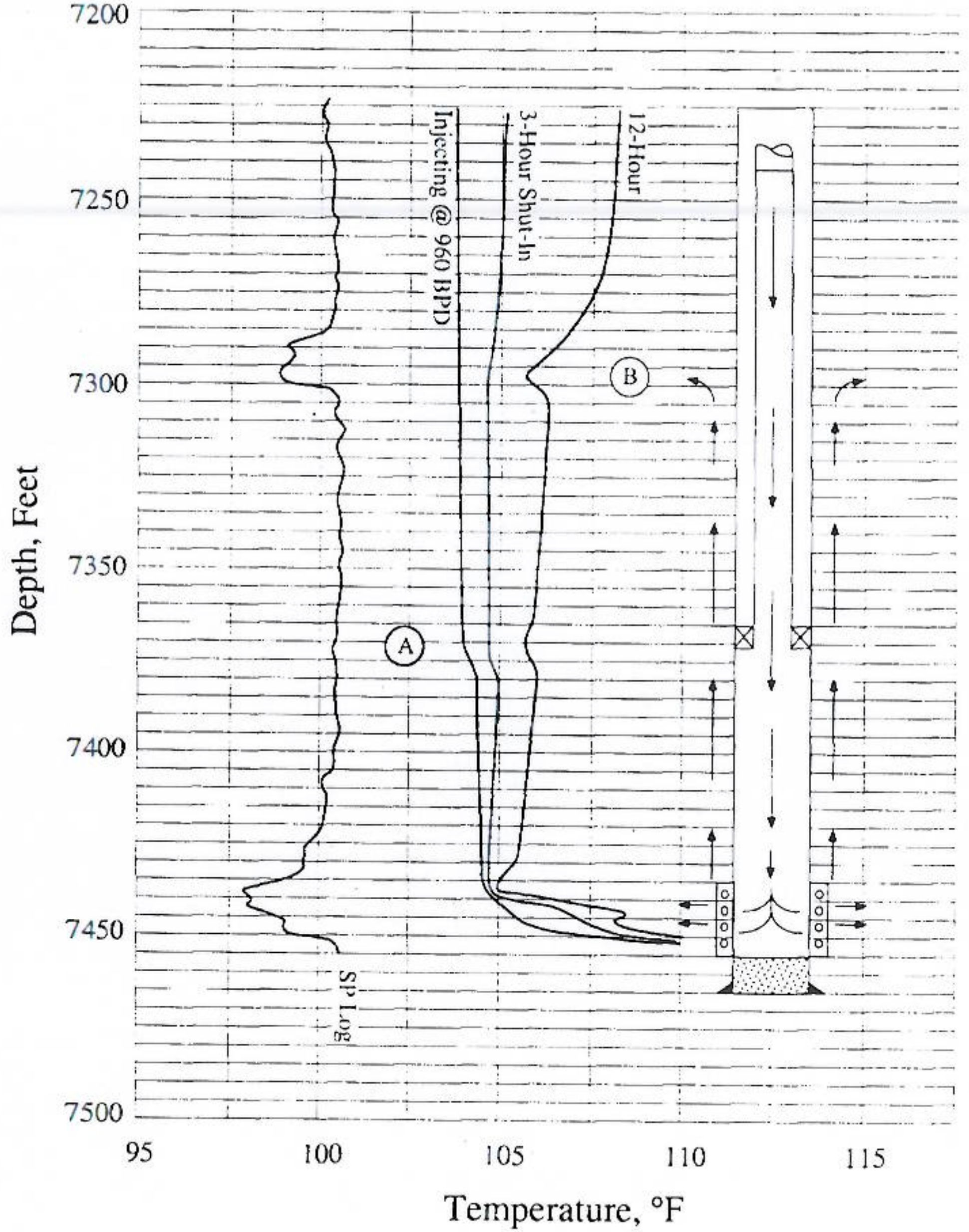


Figure 22. **Temperature surveys from a well on injection at 960 BPD with flow behind pipe even on shut-in status.**

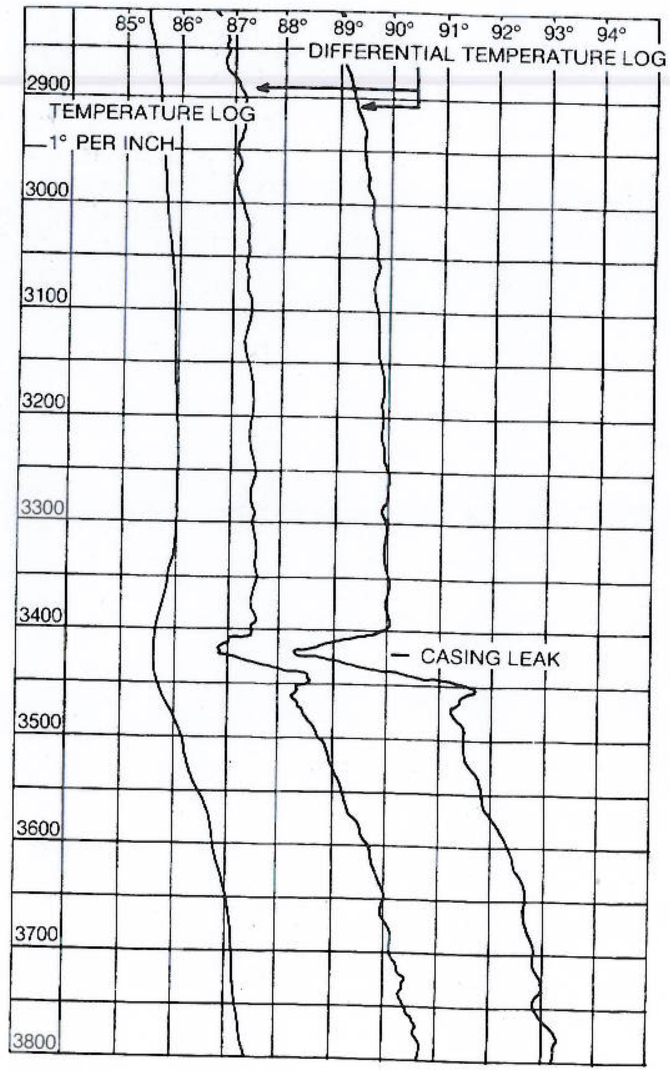
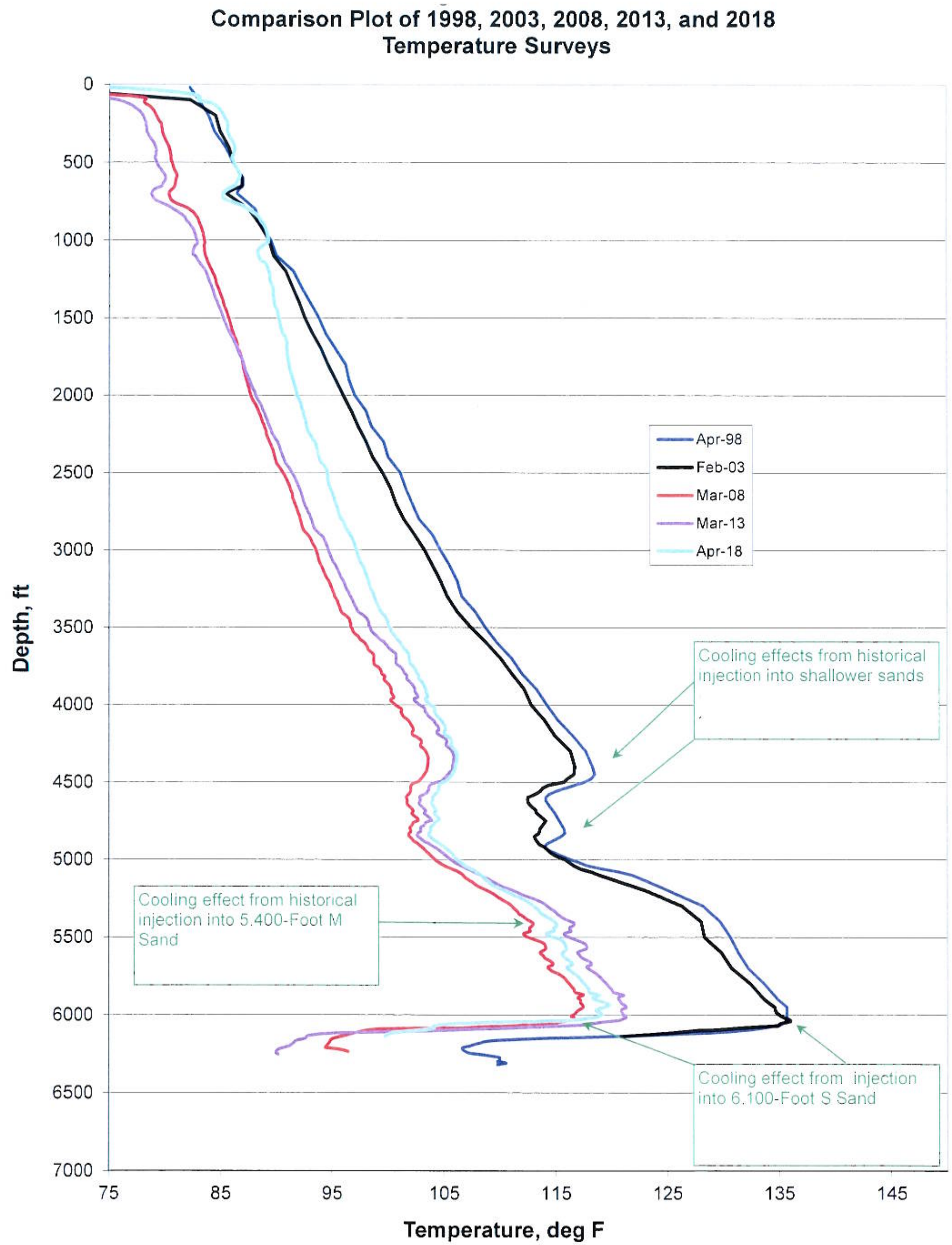
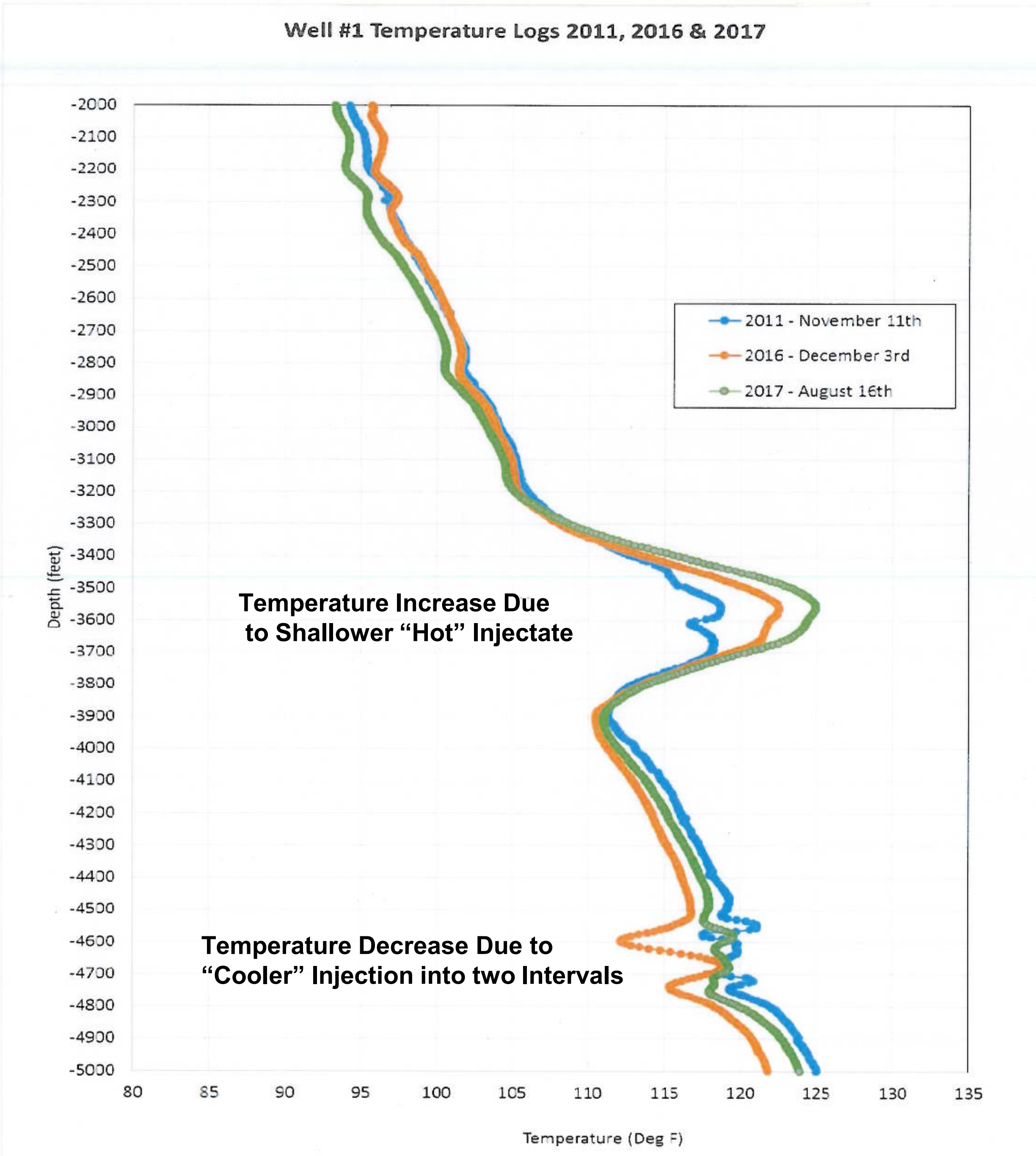


Figure 22. Temperature logs used in locating a casing leak (Peacock, 1965).



Comparison Plot of 1998, 2003, 2008, 2013, and 2018
Temperature Surveys
Depth, ft
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
5500
6000
6500
7000
75
85
95
105
115
125
135
145
Temperature, deg F
Apr-98
Feb-03
Mar-08
Mar-13
Apr-18
Cooling effects from historical injection into shallower sands
Cooling effect from historical injection into 5,400-Foot M Sand
Cooling effect from injection into 6,100-Foot S Sand


Well #1 Temperature Logs 2011, 2016 & 2017
Depth (feet)
-2000
-2100
-2200
-2300
-2400
-2500
-2600
-2700
-2800
-2900
-3000
-3100
-3200
-3300
-3400
-3500
-3600
-3700
-3800
-3900
-4000
-4100
-4200
-4300
-4400
-4500
-4600
-4700
-4800
-4900
-5000
80
85
90
95
100
105
110
115
120
125
130
135
Temperature (Deg F)
2011 - November 11th
2016 - December 3rd
2017 - August 16th
Temperature Increase Due to Shallower "Hot" Injectate
Temperature Decrease Due to "Cooler" Injection into two Intervals

NOISE LOG

(External MI)

NOISE LOG PURPOSE

- TO “HEAR” FLUID FLOW OCCURRING INSIDE OR OUTSIDE WELL TUBULARS

  ✓ BEHIND CASING CHANNELS (water flow pressure drop OR gas thru liquid)

  ✓ TUBING AND/OR CASING LEAKS

NOISE LOG OPERATION PRINCIPLES

- **FLUID TURBULENCE (FLOW) - - - NOISE**
- **NOISE OCCURS OVER A RANGE OF FREQUENCIES - - TYPICAL TO THE KIND OF FLOW CREATED**
  - **GAS flow upward thru liquid**
    - » **Flows in "bubbles" which "ring"**

NOISE LOG
OPERATION PRINCIPLES

- FLUID TURBULENCE (FLOW) - - - NOISE
- NOISE OCCURS OVER A RANGE OF FREQUENCIES - - TYPICAL TO THE KIND OF FLOW CREATED
  - FLUID turbulence when forced across constriction – pressure drop

NOISE LOG
OPERATION PRINCIPLES

- FLUID TURBULENCE (FLOW) - - - NOISE
- NOISE OCCURS OVER A RANGE OF FREQUENCIES - - TYPICAL TO THE KIND OF FLOW CREATED
  - 200 Hz (cycles per second)
  - 600 Hz
  - 1000 Hz
  - 2000 Hz

NOISE LOG EQUIPMENT

- TRANSDUCER (converts sound to electrical signal - to be amplified)
- FREQUENCY SEPARATING FILTERS
- SPEAKER (esp. headphones for operator)
- TYPICAL SIZE = 1¾ inch X 3½ feet (as small as 1 inch O.D.)

NOISE LOG CHARACTERISTICS

ESSENTIAL TO INTERPRETATION

- **LOUDNESS** - measured levels above ambient... amplitude... on all 4 frequencies

  - severity of the problem

- **CHARACTER** – variation in level on a particular cut from station to station is related to the path of flow

  - how flow is taking place

- **PITCH** – frequency content of sound at a peak in noise level

  - type of flow (single phase or gas thru liquid)

NOISE LOG
OPERATION GUIDELINES

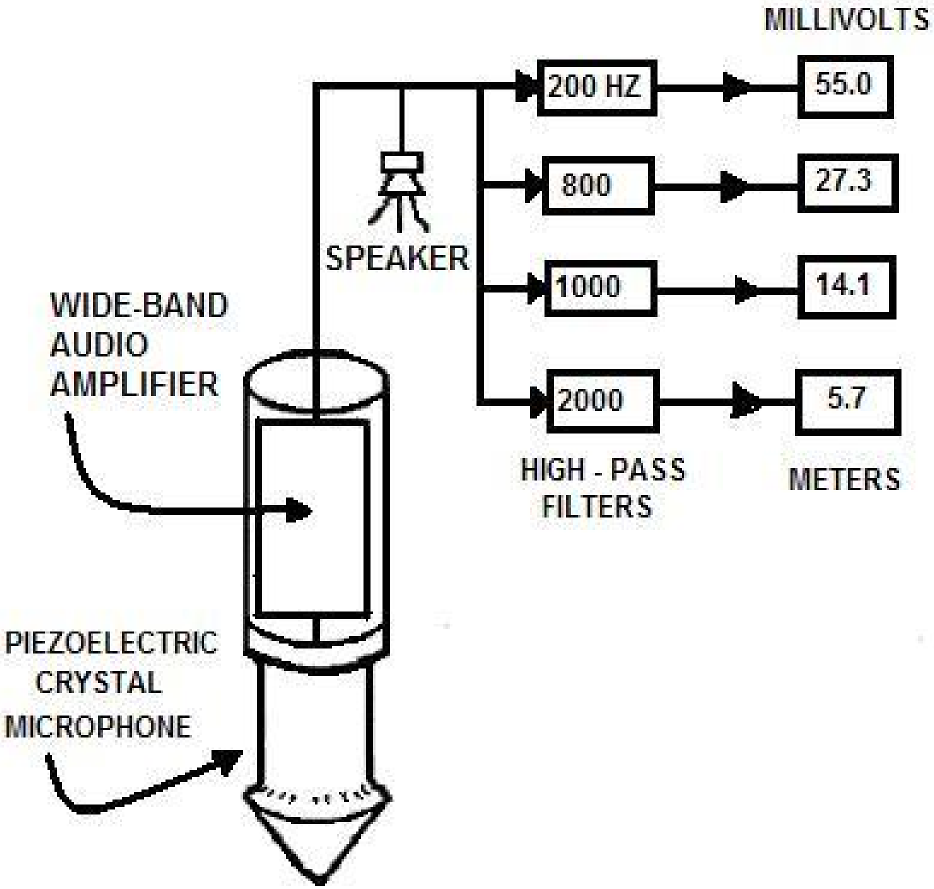
- Logging Sonde takes readings at different depths while STATIONARY.
- Log can be utilized in virtually any DOWNHOLE CONDITION (liquid or gas filled).
- APPLY CRITERIA

NOISE LOG
OPERATION CRITERIA

- Operator consults CONSTRUCTION DETAILS
- WELL SHUT-IN (for behind-pipe flow)
- Record Noise Levels at the 4 FREQUENCIES (200Hz, 600Hz, 1000Hz, 2000Hz)
- MINIMUM READINGS taken opposite the Confining Layer, Base of USDWs and Well Construction changes
- SPACING: readings every 50 to 200 feet (low noise areas); 10 feet or less (zones of interest)
- READING TIMES of 3 or more minutes each

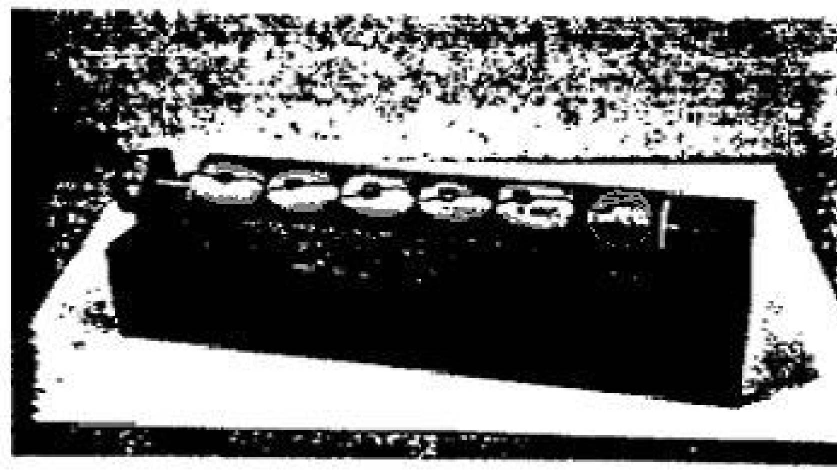
EXAMPLE NOISE LOG PROCEDURE

- **PULL TUBING ONLY if necessary**
- **RUN BASE LOG – well shut-in**
- **START INJECTION (if necessary to initiate flow)**
- **RUN NOISE LOG – at same base log stops**
- **ENSURE TOOL IS STATIONARY at stops**
- **At ZONES OF INTEREST, perform readings at 10 ft. intervals plus/minus for locating source**



TOOL SCHEMATIC

SIX PIEZOELECTRIC CRYSTALS



CRYSTALS ASSEMBLED FOR ENCAPSULATION

Noise (sound) logging sonde with piezoelectric detection elements shown separately

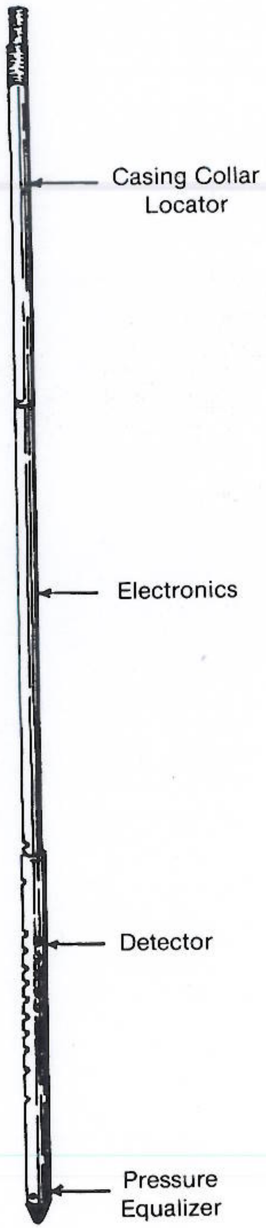
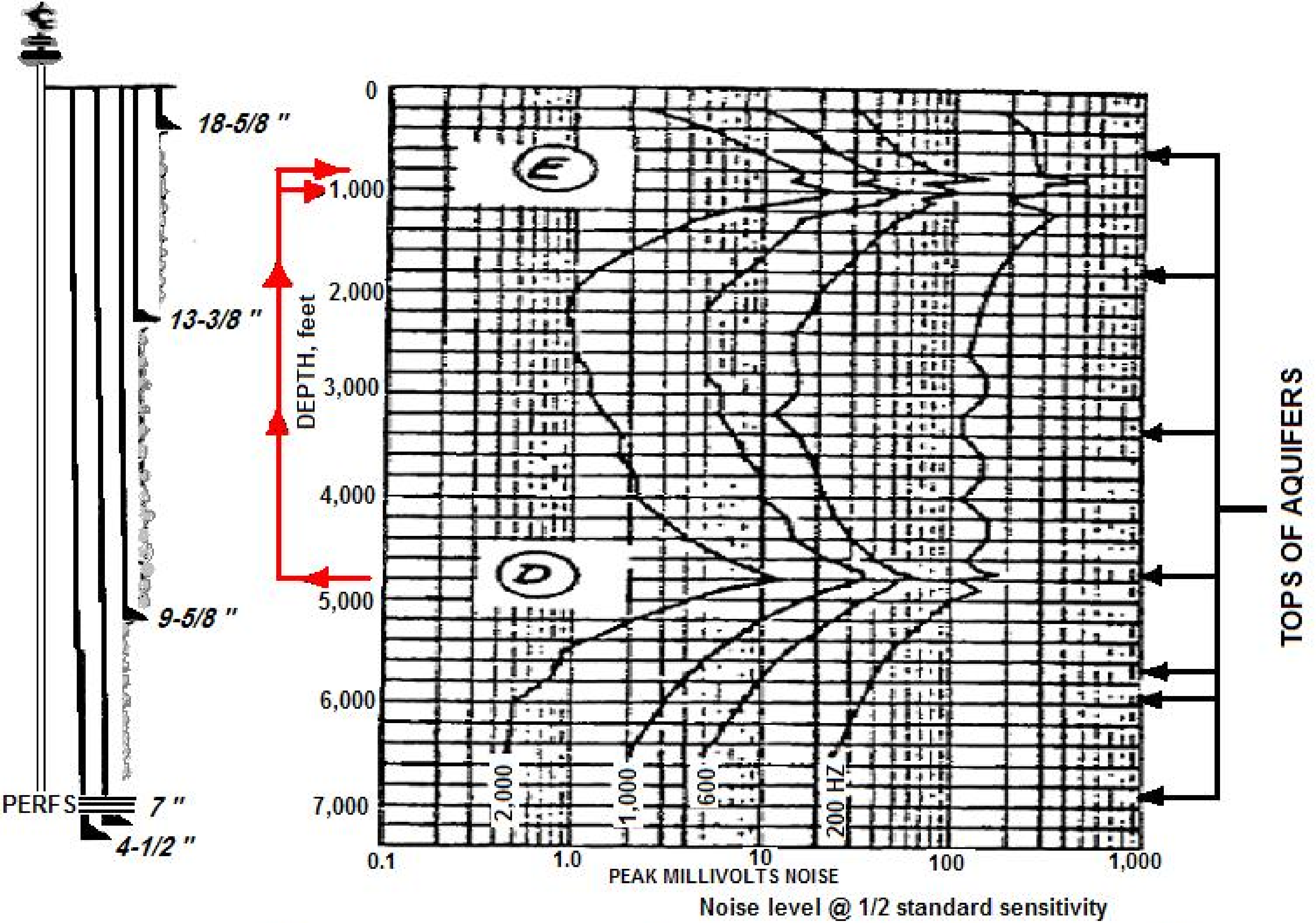


Figure 24. Typical noise logging tool (Robinson, 1976b).



Noise log from shut-in well with water flow behind pipe @ 5,000 BPD estimated rate

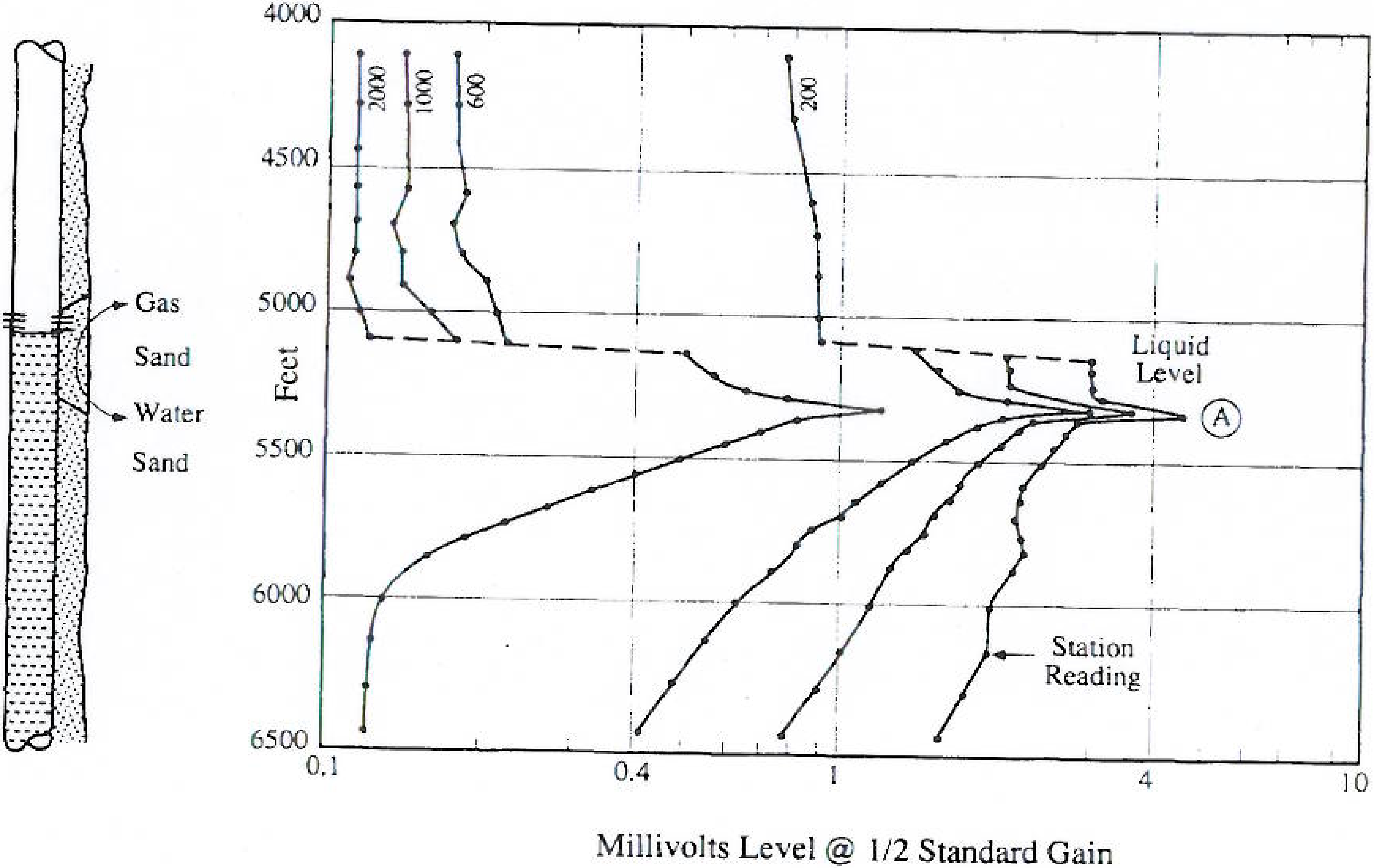


Figure 79. **Noise log format with a 20-BPD water flow behind pipe into a gas zone depleted by 250 PSI.**

OXYGEN ACTIVATION

TRACER SURVEYS

(OA Logs)

(External MI)

OA LOG
PURPOSE

- Determine presence of
  FLUID FLOW BEHIND CASING

- Measure
  - Flow DIRECTION
  - Linear Flow VELOCITY
  - Volume Flow RATE ESTIMATE
  - RADIAL DISTANCE From Tool

OA LOG
PRINCIPLE OF OPERATION

- **Similar to Radioactive Tracer Survey (RATS)**
- **Tracer is CREATED within the flowing water behind the casing**
  - **Water behind pipe is bombarded with ENERGETIC NEUTRONS**
  - **Radioactive Nitrogen Isotope with half-life of 7 seconds formed when neutrons react with oxygen in water**
- **EMMITED GAMMA RAYS detected by two detectors at different distances**

OA LOG LIMITATIONS

- **DEPTH OF INVESTIGATION**
  (approximately 12 inches)

- **FLUID COMPOSITION**
  (must contain Oxygen)

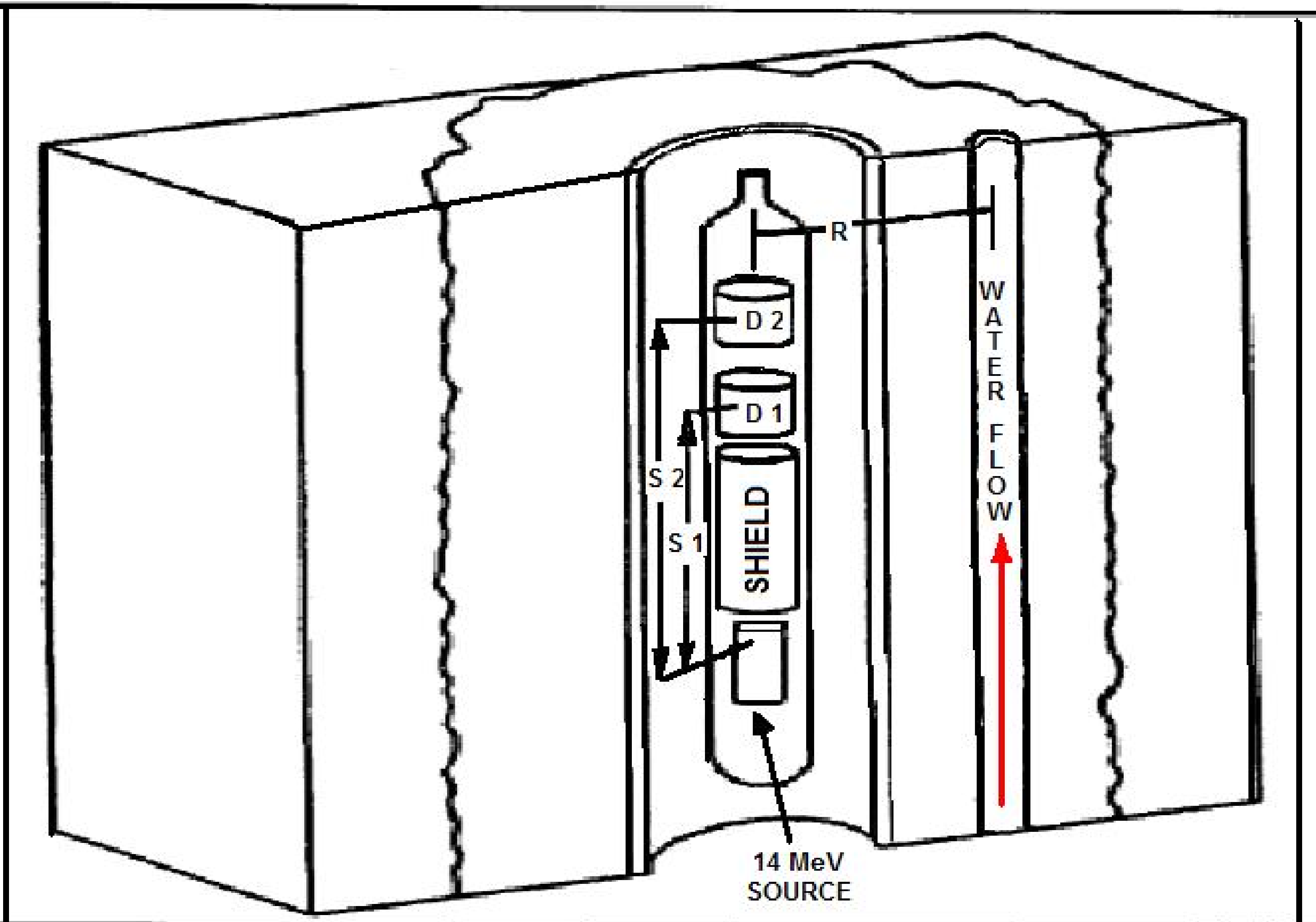
- **FLUID VELOCITY**

OA LOG EQUIPMENT

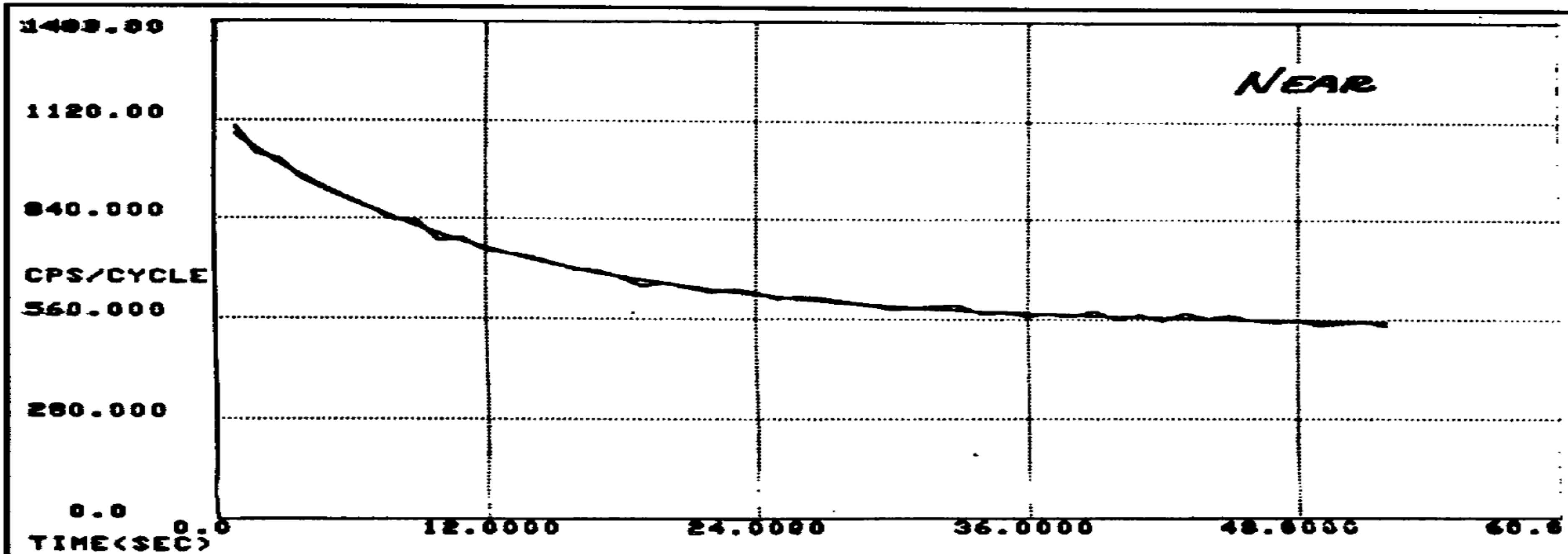
- **NEUTRON SOURCE**
- **NEUTRON SHIELD**
- **2 GAMMA RAY DETECTORS**
  above source to detect upward flow
- **TOOL SIZES**
  1-3/4 to 3-5/8 inches X 34 to 26 feet
- **COMPUTER ANALYSIS @ surface**

OA LOG PROCEDURE

- RUN LOG @ NORMAL INJECTION RATE
- CALIBRATE INSTRUMENT
- RUN BASE GAMMA-RAY LOG
- LOG @ 10 FT. STOPS (5 MIN. EA.) START BELOW PERFS (NO FLOW)
  - RELEASE SOURCE
  - READINGS FOR 5 MINUTES
  - REPEAT 10 FEET UP HOLE



OXYGEN ACTIVATION TOOL SCHEMATIC



FILE NUMBER
25

DATA ACQUIRED
05-DEC-1990 11:38

DETECTOR = NEAR TDT-P

DEPTH = 2493.6 F

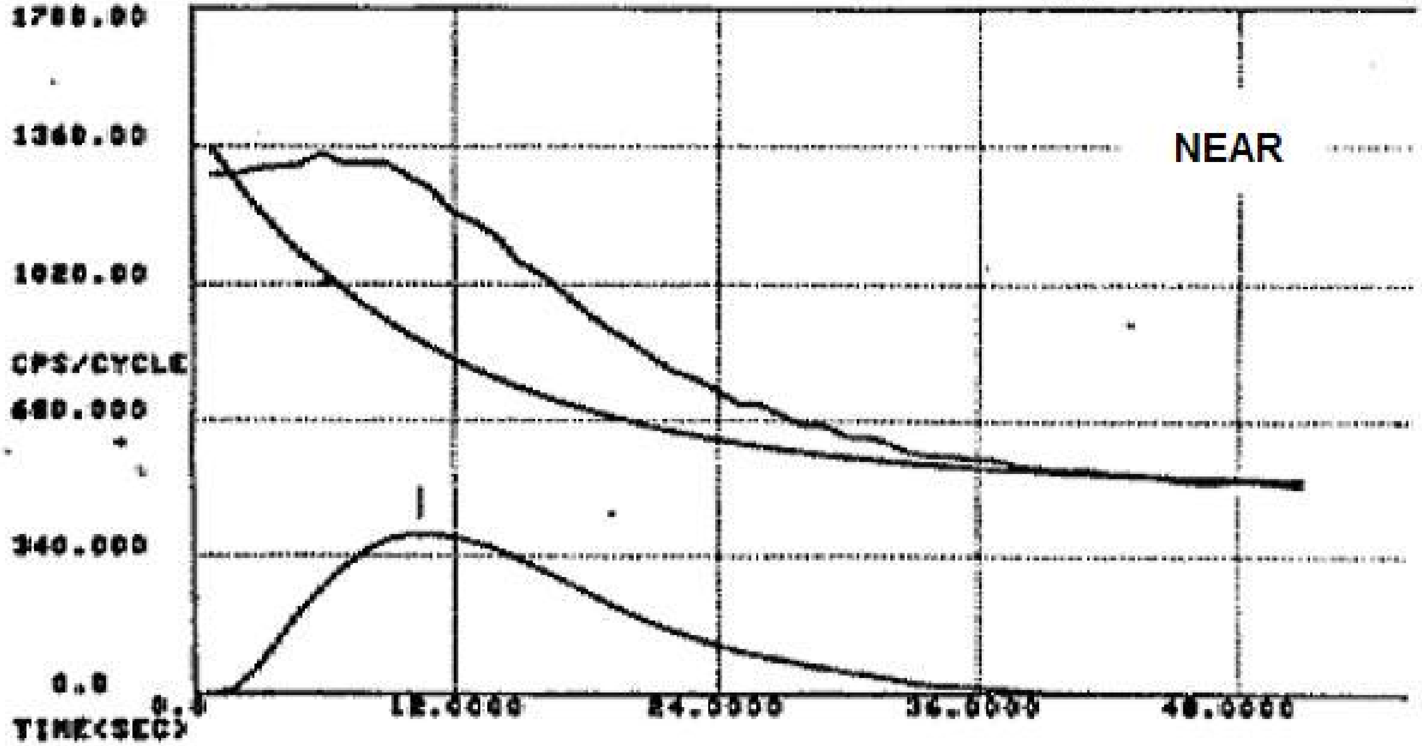
CASING SIZE = 7.000 IN
NEAR TCHK = 51377.0 CPS
NEUTRON ON TIME = 10.0 S

SFT TYPE = 178
FAR TCHK = 23345.0 CPS
NUMBER OF CYCLES SUMMED = 12

FLOW NOT DETECTED
FLOW VELOCITY = 0.0 FT / MINUTE
FLOW RATE = 0.0 BWPD

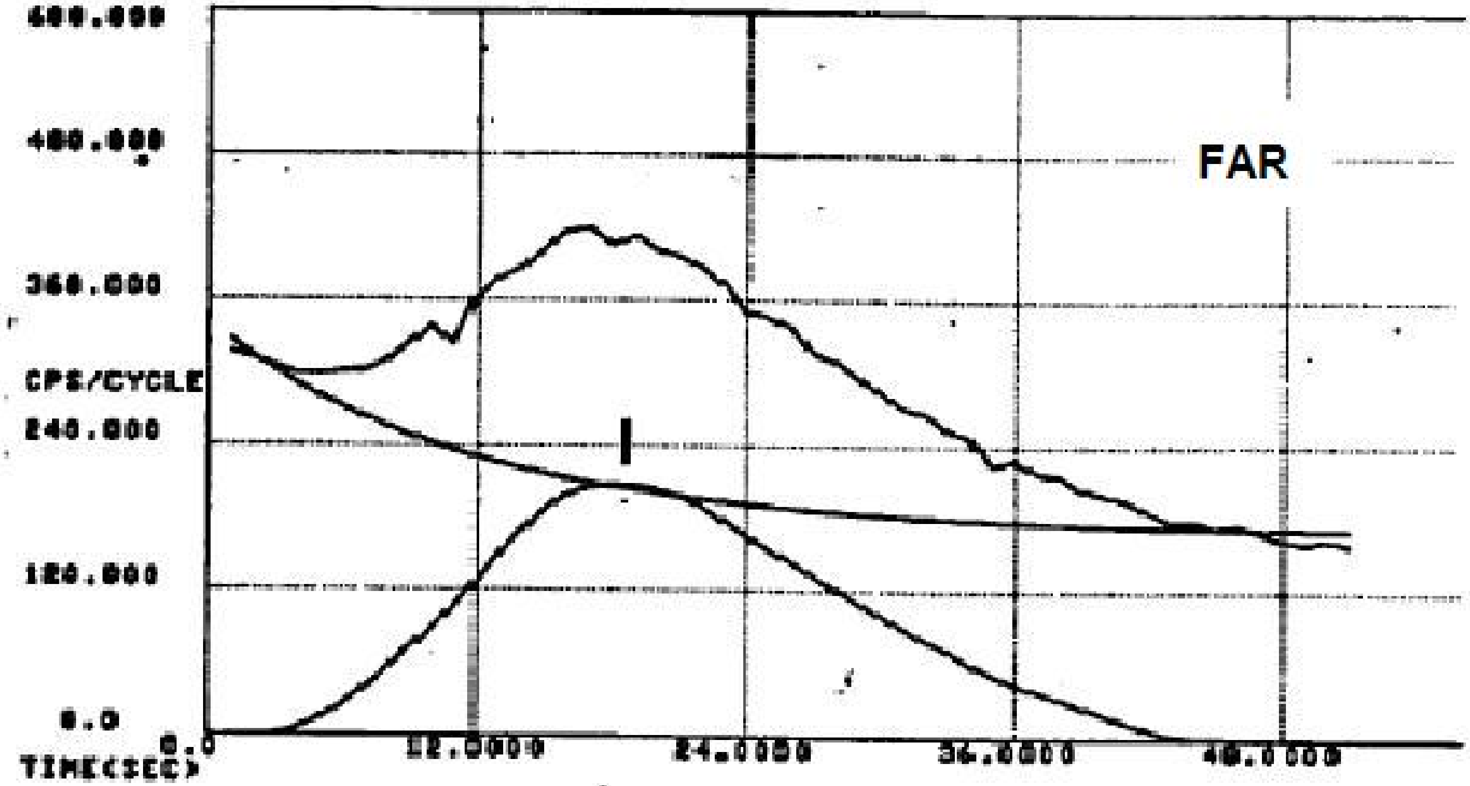
PEAK BACKGROUND SIGNAL = 556.9 +/- 1.3 CPS / CYCLE
PEAK STATIONARY SIGNAL = 548.7 +/- 4.8 CPS / CYCLE
TOTAL FLOWING SIGNAL = 0.0 +/- 0.0 COUNTS / CYCLE

Figure 31A. Mechanical integrity (near counter) at 2493.6 ft




```
FILE NUMBER                    DATA ACQUIRED
  44                           05-DEC-1990 10:23

    DETECTOR = NEAR TDT-P                    DEPTH =  3293.6 F

CASING SIZE       =    7.000 IN     SFT TYPE                   =  178
NEAR TCHK         = 43200.0 CPS     FAR TCHK                   = 21200.0 CPS
NEUTRON ON TIME   =     10.0 S      NUMBER OF CYCLES SUMMED    =    12

FLOW DETECTED
FLOW VELOCITY  =    -1.0 FT / MINUTE
FLOW RATE      =    -1.0 BWPD

PEAK BACKGROUND SIGNAL =   533.9   +/-    1.5 CPS / CYCLE
PEAK STATIONARY SIGNAL =   856.6   +/-    4.3 CPS / CYCLE
TOTAL FLOWING SIGNAL   =  6403.3   +/-   40.1 COUNTS / CYCLE
```

SAMPLE AVERAGE SPECTRUM NEAR COUNTER



FILE NUMBER
44

DATA ACQUIRED
05-DEC-1990 18:23

DETECTOR = FAR TDT-P

DEPTH = 3293.6 F

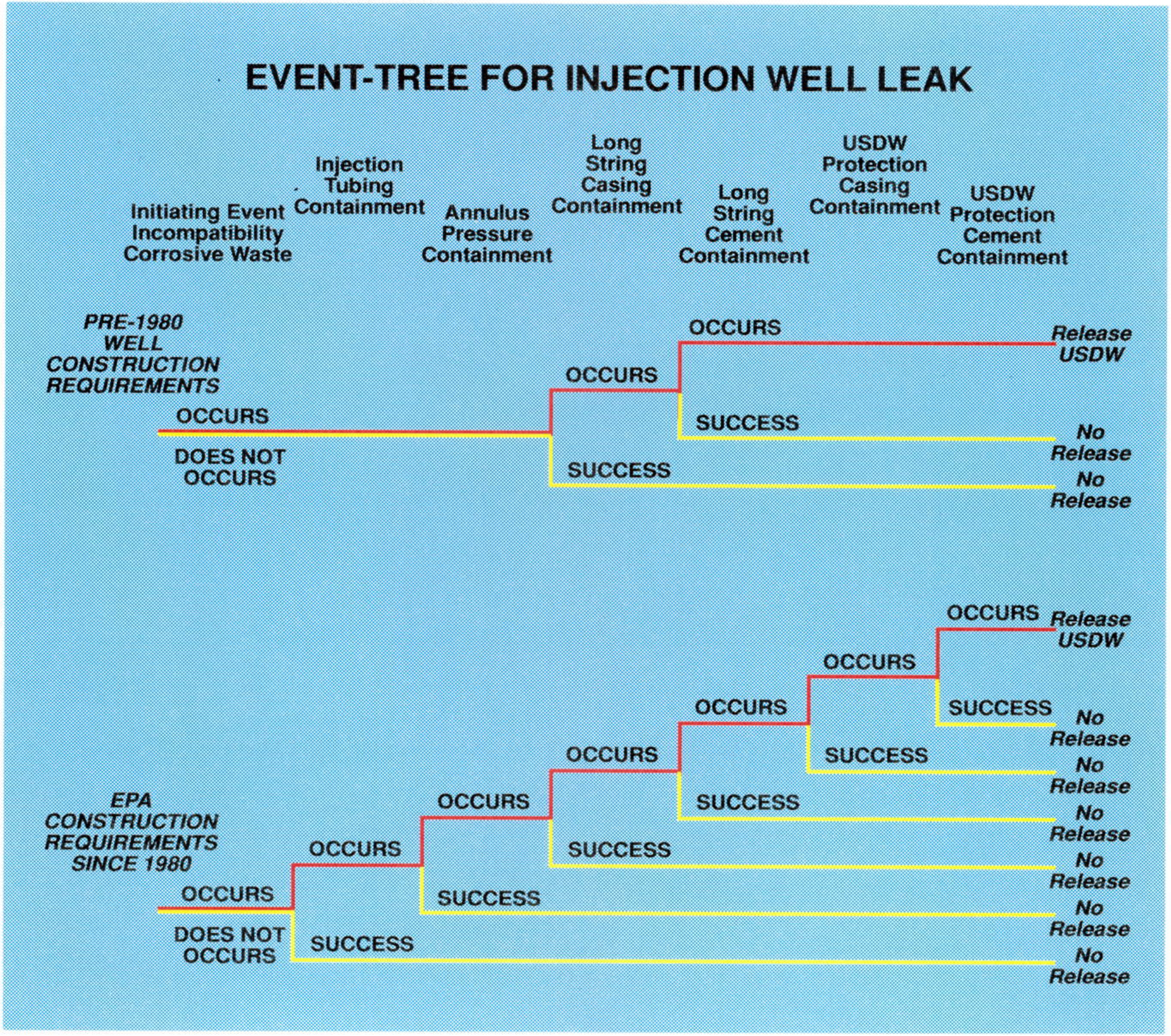
CASING SIZE = 7.000 IN
NEAR TCHK = 43200.0 CPS
NEUTRON ON TIME = 10.0 S

SFT TYPE = 178
FAR TCHK = 21200.0 CPS
NUMBER OF CYCLES SUMMED = 12

FLOW DETECTED
FLOW VELOCITY = 3.0 FT / MINUTE
FLOW RATE = 277.9 BWPD

PEAK BACKGROUND SIGNAL = 173.3 +/- 1.0 CPS / CYCLE
PEAK STATIONARY SIGNAL = 160.8 +/- 2.8 CPS / CYCLE
TOTAL FLOWING SIGNAL = 4079.7 +/- 35.0 COUNTS / CYCLE

SAMPLE AVERAGE SPECTRUM FAR COUNTER


EVENT-TREE FOR INJECTION WELL LEAK
Initiating Event Incompatibility Corrosive Waste
Injection Tubing Containment
Annulus Pressure Containment
Long String Casing Containment
Long String Cement Containment
USDW Protection Casing Containment
USDW Protection Cement Containment
PRE-1980 WELL CONSTRUCTION REQUIREMENTS
OCCURS
DOES NOT OCCURS
OCCURS
OCCURS
SUCCESS
SUCCESS
Release USDW
No Release
No Release
EPA CONSTRUCTION REQUIREMENTS SINCE 1980
OCCURS
DOES NOT OCCURS
OCCURS
OCCURS
OCCURS
OCCURS
OCCURS
OCCURS
SUCCESS
SUCCESS
SUCCESS
SUCCESS
SUCCESS
SUCCESS
Release USDW
No Release
No Release
No Release
No Release
No Release
No Release