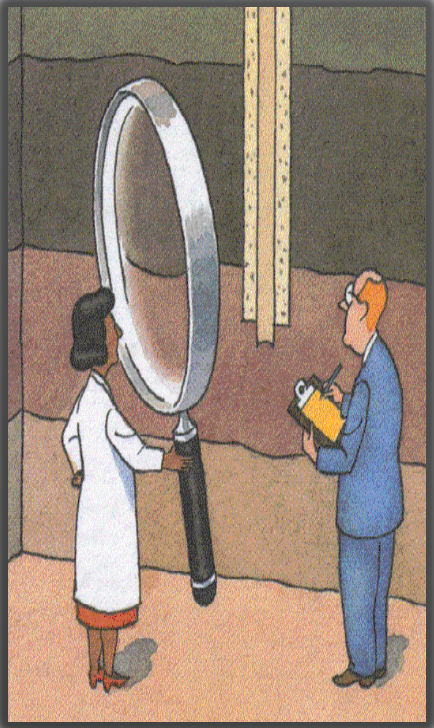
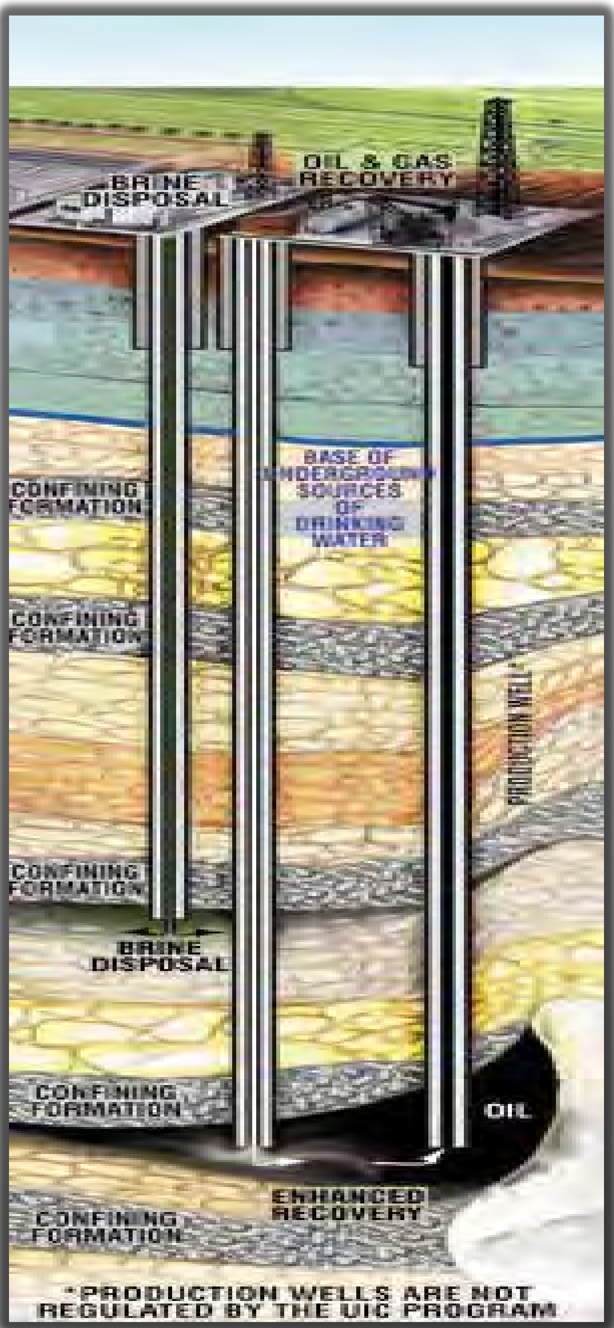
Webinar No. 2
Class II UIC
Mechanical Integrity

Class II UIC Program Technical History & Program Evolution Webinar Series

GROUNDWATER PROTECTION COUNCIL

ALL CONSULTING





DEFINING MECHANICAL INTEGRITY

Part I and II Mechanical Integrity Testing (MIT)

- Demonstrating Mechanical Integrity:
  - Class II injection wells must demonstrate two (2) parts of mechanical integrity prior to commencement of injection operations.
  - Under 40 CFR 146.8 it states that an injection well has mechanical integrity if:
    - Part I (Internal Mechanical Integrity) – There is no significant leak in the production casing, injection tubing, or the packer.
    - Part II (External Mechanical Integrity) – There is no significant fluid movement into USDWs through vertical channels adjacent to the injection wellbore.

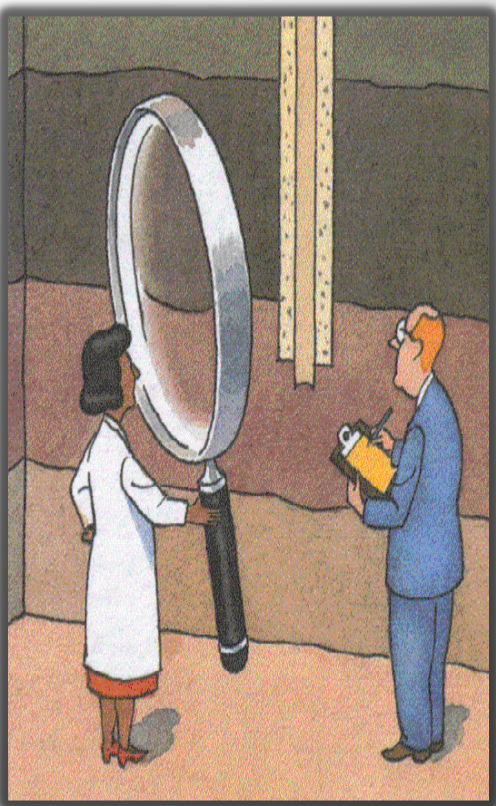
Source: ALL Consulting, 2015

Part I - Internal Mechanical Integrity

- Part I of mechanical integrity is typically demonstrated by what is called the Standard Annulus Pressure Test (SAPT).
- An initial SAPT is conducted prior to commencement of injection operations.
- Then an internal mechanical MIT must be conducted and passed once every five years.
- Alternate testing methods may be allowed depending on circumstances, well configurations, etc.

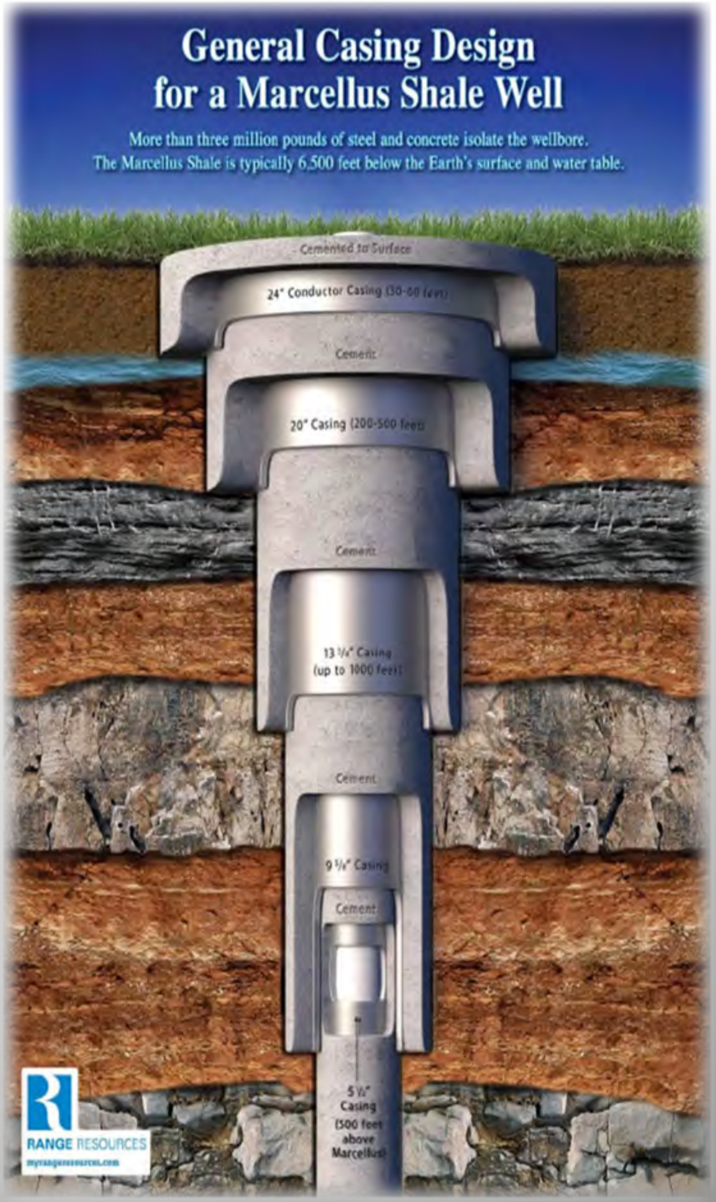
Part II – External Mechanical Integrity (MIT)

- External MIT is required to demonstrate that there is no significant fluid movement into USDWs through vertical channels adjacent to the injection wellbore.
- Part II of mechanical integrity is commonly accomplished by the review of cementing records and calculation of the top of cement or by temperature log or CBL to determine that the top of cement above the injection zone behind the production casing meets the regulatory requirements.
- Additional testing such as a radioactive tracer survey may be required to demonstrate Part II of mechanical integrity.



Barriers of Protection

- Failure of well integrity does NOT always equate to contamination.
- Wells are completed with multiple barriers of protection for this very purpose.
- Generally, for contamination to occur, multiple integrity failures and operational oversights must take place.



WELL INTEGRITY TESTS

CLASS II INJECTION WELL INTEGRITY (INTERNAL) IN TEXAS

AN EXAMPLE OF HOW PART I MIT CAN BE IMPLEMENTED BY A STATE AGENCY

When are Integrity Tests Required?

- Prior to beginning injection
- Every 5 years by Statewide Rule
- More frequently by Permit Special Conditions
  - For wells with short surface casing
- After workover:
  - When tubing-packer-casing seal is disturbed
  - When casing is repaired
- Whenever mechanical integrity is in doubt

Texas RRC Form H-5

- 48 hours notice required to the District Office.
- Form H-5 must be filed within 30 days.
- Pressure recording chart is required if not witnessed by the RRC.

Form H-5
06/03/85

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division
Disposal/Injection Well
Pressure Test Report

READ INSTRUCTIONS ON BACK
PLEASE TYPE OR PRINT

UIC CONTROL NO. ____
Type ____
FOR RRC USE ONLY

1. OPERATOR'S NAME
2. RRC OPERATOR NO.
3. ADDRESS
4. RRC DISTRICT NO.
5. COUNTY
6. FIELD NAME (Exactly as shown on proration schedule)
7. FIELD NO.
8. API NO.
9. LEASE NAME
10a. OIL LEASE NO.
10b. GAS ID NO.
11. WELL NO.

12. REASON FOR TEST
- ☐ Initial Test Prior to Injection
- ☐ After Workover
- ☐ Annual Test Required By Permit
- ☐ Five-Year Test Required By Rule
- ☐ Other (Specify) ____

13. DATE OF TEST
14. RETEST? ☐ YES ☐ NO
If YES, see Instruction No. 5

15. WELL COMPLETION

	size	depth set
Surface Casing	____	____
Long String Casing	____	____
Tubing	____	____

16a. PACKER MAKE AND MODEL
16b. DEPTH SET
17. AUTHORIZED INJECTION PRESSURE (PSIG): ____

18a. PERMITTED INJECTION INTERVAL
Top Bottom
18b. COMPLETED INJECTION INTERVAL
Top Bottom

19. TEST PRESSURE (PSIG) [see Instructions 4(c) and 4(d)]

TIME	TUBING	CASING	SURFACE CSG.	TIME	TUBING	CASING	SURFACE CSG.
Initial							
15 min.							
30 min.							

20. CHARACTERISTICS OF INJECTION FLUID
[see Instruction 4(e)]

21. CHARACTERISTICS OF ANNULUS FLUID
[see Instructions 4 (e) and 4(f)]

22. TEST WITNESSED BY RRC? ☐ YES ☐ NO
If NO, see Instruction 4(a)
If YES, Name of RRC Representative ____

23. WERE OTHER TESTS/SURVEYS PERFORMED AT THIS TIME? ☐ YES ☐ NO. If YES, List:

24. OPERATOR COMMENTS ON TEST (attach separate sheet if necessary)

25. WELL STATUS: ☐ Active ☐ Temporarily Abandoned ☐ Other (Specify) ____

CERTIFICATE:

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated herein are true, correct, and complete, to the best of my knowledge.

Signature
Name of Person (type or print) Title
Telephone No. ( ) Date

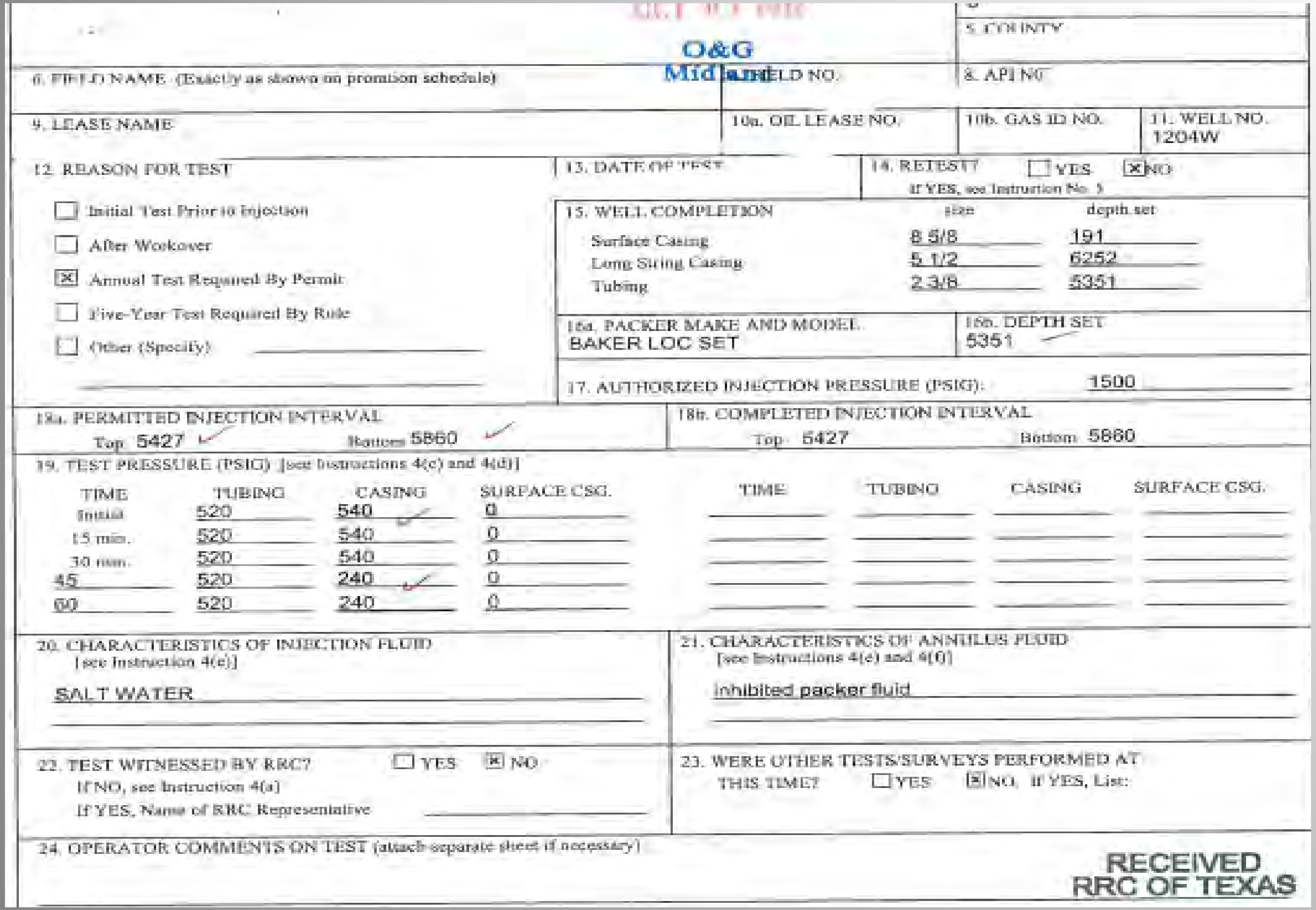
SAPT Requirements

- Pressure Recorder
  - One-pen record for casing test pressure
  - Test pressure within 30-70% of chart
  - Clock rotation must not exceed 24 hours
  - Chart must be signed by Operator’s field rep.
- Pressure Gauge
  - Gauges required on tubing and each casing annulus
  - Gauges verify chart record readings
  - Test pressure within 30-70% of gauge
  - Gauge face marked in 5% increments of test pressure

Test Pressure Requirements

- If permit pressure is 200 psi or less
  - 200 psig minimum test pressure required
- If permit pressure is between 200-500 psi
  - Test at permit pressure
- If permit pressure is 500 psi or more
  - Injectors with tubing & packers test at 500 psig
  - Casing injectors test at max permitted pressure
- Maintain 200 psi tubing/casing differential

Example of Two-Part Test



O&G Midland

5. COUNTY

6. FIELD NO. NAME (Exactly as shown on proration schedule) | 7. FIELD NO. | 8. API NO.

9. LEASE NAME | 10a. OIL LEASE NO. | 10b. GAS ID NO. | 11. WELL NO. 1204W

12. REASON FOR TEST

- [ ] Initial Test Prior to Injection
- [ ] After Workover
- [x] Annual Test Required By Permit
- [ ] Five-Year Test Required By Rule
- [ ] Other (Specify)

13. DATE OF TEST

14. RETEST? [ ] YES [x] NO — If YES, see Instruction No. 3

15. WELL COMPLETION

	size	depth set
Surface Casing	8 5/8	191
Long String Casing	5 1/2	6252
Tubing	2 3/8	5351

16a. PACKER MAKE AND MODEL: BAKER LOC SET

16b. DEPTH SET: 5351

17. AUTHORIZED INJECTION PRESSURE (PSIG): 1500

18a. PERMITTED INJECTION INTERVAL — Top 5427 Bottom 5860

18b. COMPLETED INJECTION INTERVAL — Top 5427 Bottom 5860

19. TEST PRESSURE (PSIG) [see Instructions 4(c) and 4(d)]

TIME	TUBING	CASING	SURFACE CSG.	TIME	TUBING	CASING	SURFACE CSG.
Initial	520	540	0				
15 min.	520	540	0				
30 min.	520	540	0				
45	520	240	0				
60	520	240	0				

20. CHARACTERISTICS OF INJECTION FLUID [see Instruction 4(e)]
SALT WATER

21. CHARACTERISTICS OF ANNULUS FLUID [see Instructions 4(e) and 4(f)]
inhibited packer fluid

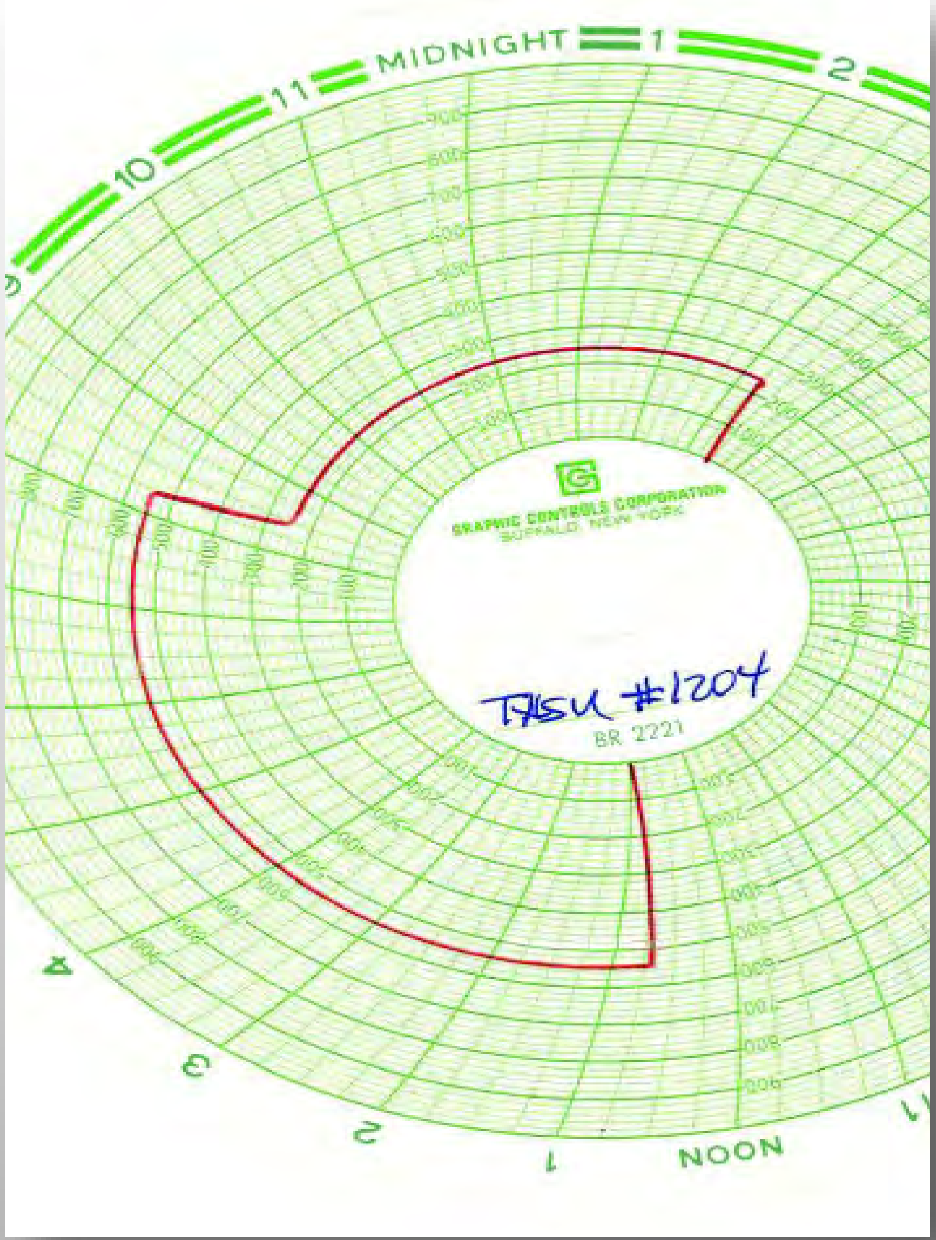
22. TEST WITNESSED BY RRC? [ ] YES [x] NO
If NO, see Instruction 4(a)
If YES, Name of RRC Representative

23. WERE OTHER TESTS/SURVEYS PERFORMED AT THIS TIME? [ ] YES [x] NO. If YES, List:

24. OPERATOR COMMENTS ON TEST (attach separate sheet if necessary)

RECEIVED
RRC OF TEXAS

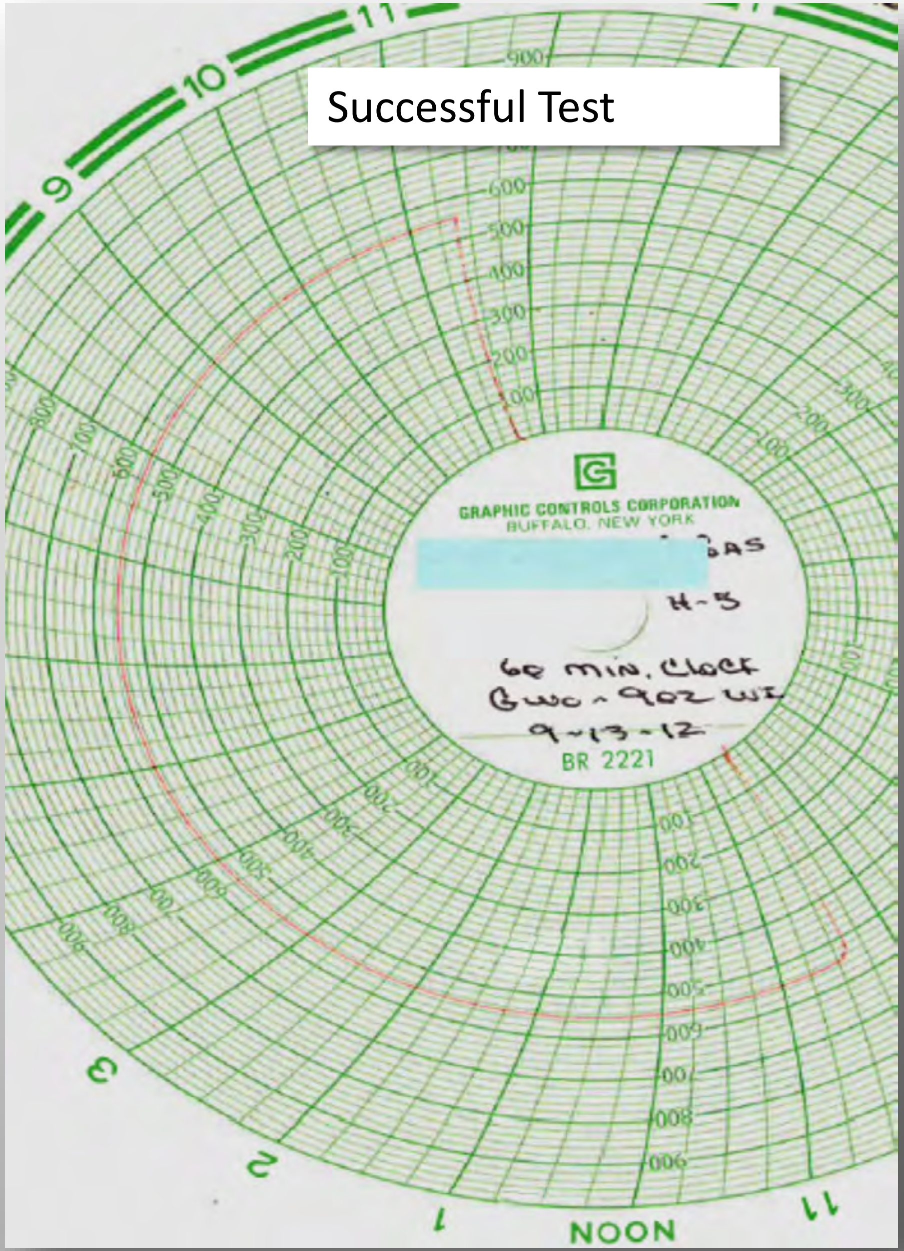
Source: Texas Railroad Commission



Source: Texas Railroad Commission

Length of Test

- A liquid-filled annulus is required for wells that inject liquids.
- For liquid-filled annulus, test pressure must stabilize within 10% of the required test pressure for at least 30 minutes
- For a gas-filled annulus, test pressure must stabilize within 10% of the required test pressure for at least 60 minutes
- Use of high viscosity packer fluids is prohibited



Anomalies/Re-Tests

- Explain any pressure anomaly that occurs during the pressure test
- List characteristic, e.g. temperature changes of injection fluid, that might explain a small pressure change
- If the H-5 is reporting a Re-test as a result of a previous test that received a Fail or Inconclusive result, check the "Yes" box in Item 14 and explain, in Item 24, any remedial action that was taken

Inconclusive Test Results

- The test pressure was less than required
- Pressure differential not at least 200 psi
- Pressure not within 30-70% of chart
- Test conducted for less than 30 or 60 minutes
- District Office not notified 48 hours in advance
- Test Pressure was within 10% but never stabilized
- Item on Form H-5 was either Blank or Incorrect
- Packer Depth shallower than that Permitted

Test Failure Options

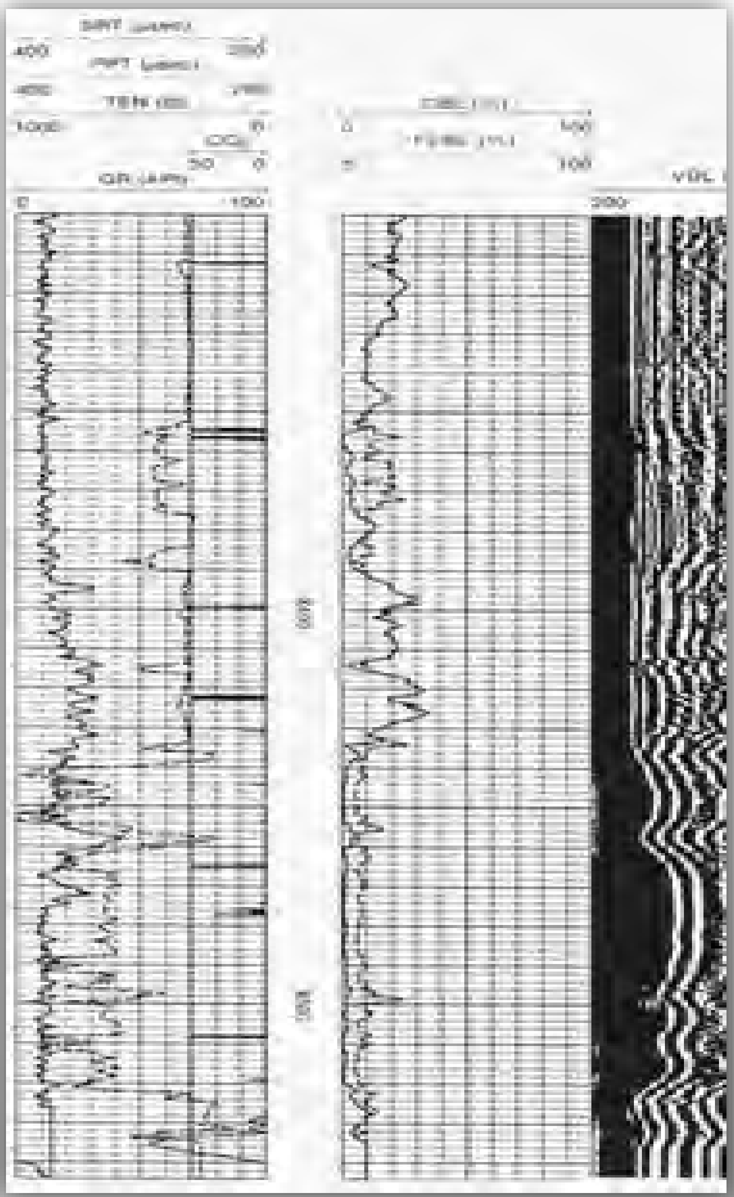
- A Failed test, as determined by the RRC review process, generates a notice, sent by mail, instructing the operator to Repair & Retest, or Plug the well within 60 days.
  – Injection must cease immediately and may not resume until well is repaired and successfully retested.

- If the well is to be plugged, send a copy of the District Office approved W-3A to UIC in Austin and the W-3 when well is plugged
  – This will expedite the resolving of the Failure since UIC does not normally get copies of the W-3A or W-3 forms

CEMENT EVALUATION LOGGING

Cement Evaluation Logging

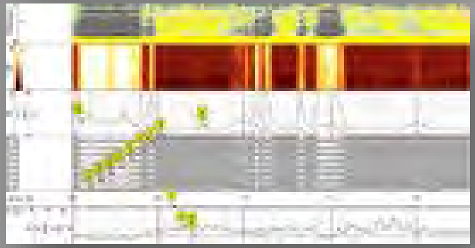
- Cement evaluation logs are utilized to locate cemented sections in the wellbore and to evaluate the quality of the cement bonding in these zones.
- Cement evaluation logs do not provide a measure of fluid movement (either water or gas) but can identify where potential void spaces exist or areas where cement may be present but is not bonded to the casing.
- Evaluating cement and cement bond quality in the presence of wellbore gas intrusion can be challenging!
- Multiple wellbore conditions must be taken into consideration to accurately evaluate cement evaluation logs.



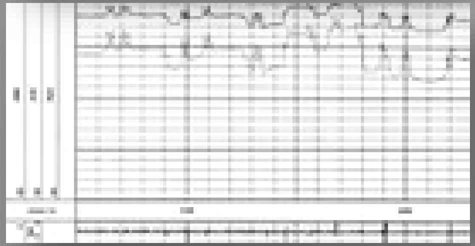
Cement Evaluation Logs

Acoustic Cement Bond Log (CBL)

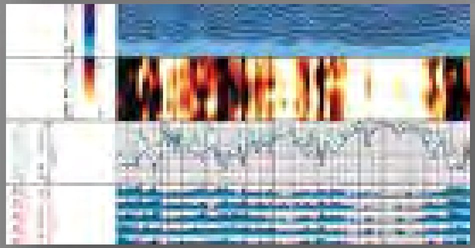
***Note:** These examples provided by Baker Hughes as an example of various logging options.*



Digital Magnelog (DMAG): Electromagnetic multi-frequency, multi-spacing casing inspection log.



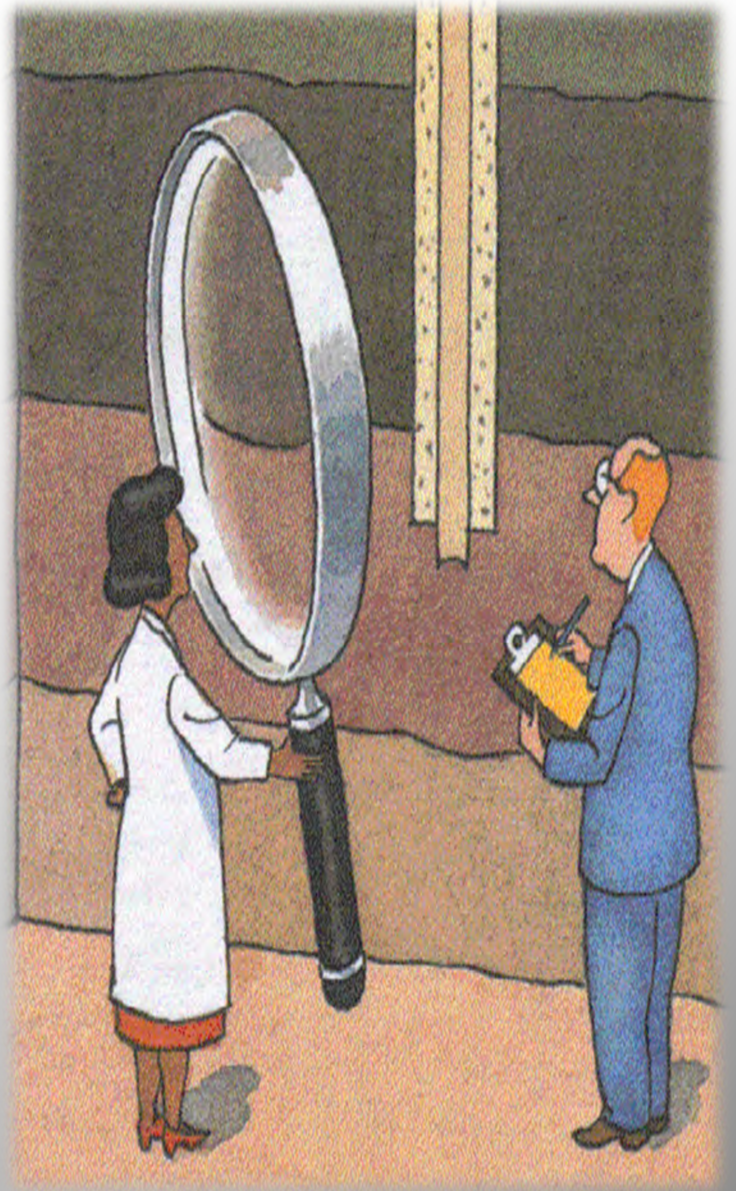
Radial Analysis Bond Log (RAL): Improved cement evaluation capabilities



Segmented Bond Log (SBT): Quantitatively measures cement bond integrity in six angular segments.

Assessing Casing & Cement

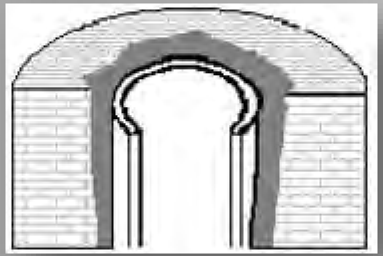
- Prior to considering logging, understanding cementing methods is critical. Insights regarding hole preparation, procedures, cement types, additives, etc. is important.
  - For instance, a lighter weight cement may show differently on a bond log than a heavier cement.
- Cementing Records
- Logging tools used for assessing cement bonding
- Physical testing

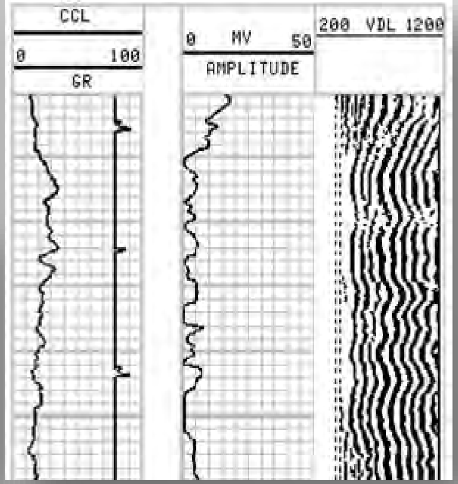


Cement Bond Long Interpretation

Good Cement

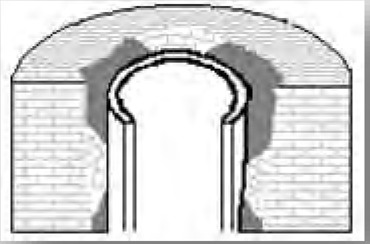
- Low Amplitude
- Strong VDL

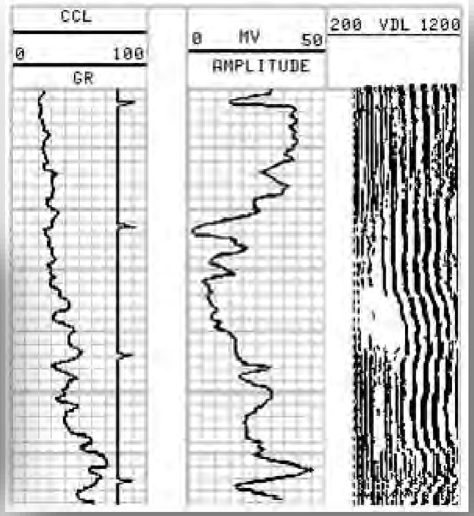




Partial Cement

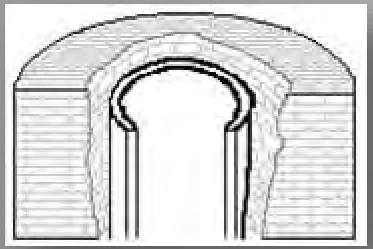
- Varied Amplitude
- Varied VDL

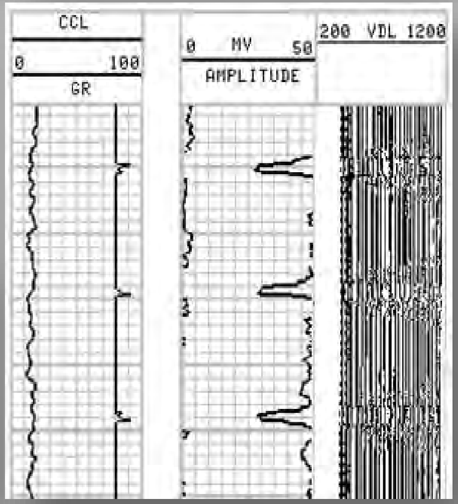




No Cement

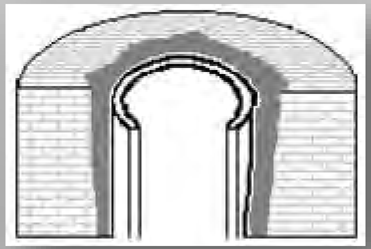
- High Amplitude
- VDL Straight
- Collars "Ringing"

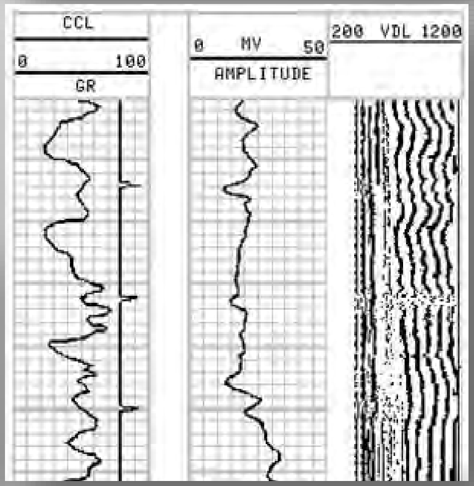




Microannulus

- Varied Amplitude
- Varied VDL
- Pressured/No Pressure

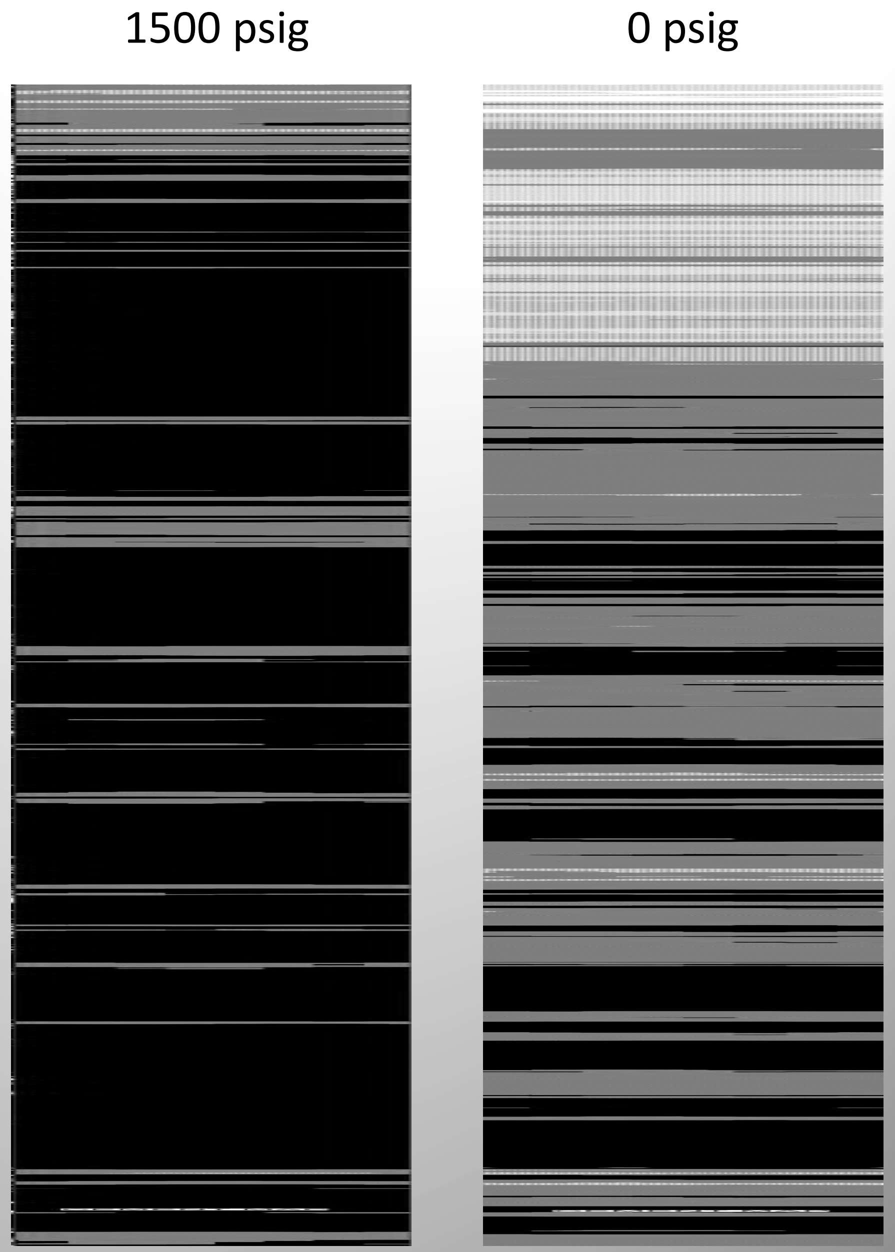




Source: www.bridge7.com

RCBL Microannulus

- A Microannulus (MA) is typically defined as a small separation between casing and cement where gas can travel, but not liquid.
- A misconception is that if a well has a MA, it is continuous over the entire wellbore.
- Actual conditions and testing reveal that often times, a MA occurs over discrete intervals (see example).
- Recognizing the presence of the MA is important when assessing EWI related to stray gas intrusion in a wellbore annular space.



Estimating the TOC

- Estimating the TOC is not always as easy as one might think.
- Even reaching a calculated TOC can be complex with the way wells are drilled today, with long-reach horizontals, varying hole sizes, varying cements, lead cement contamination, cement losses to geologic formations, etc.
- Cement evaluation logs sometimes yield unclear results or may be performed under varying conditions (e.g., multiple passes conducted under varying pressures).
- Attempting to define TOC requirements as a regulatory requirement may be unrealistic or misguided.

Log Impacts from Cement Type

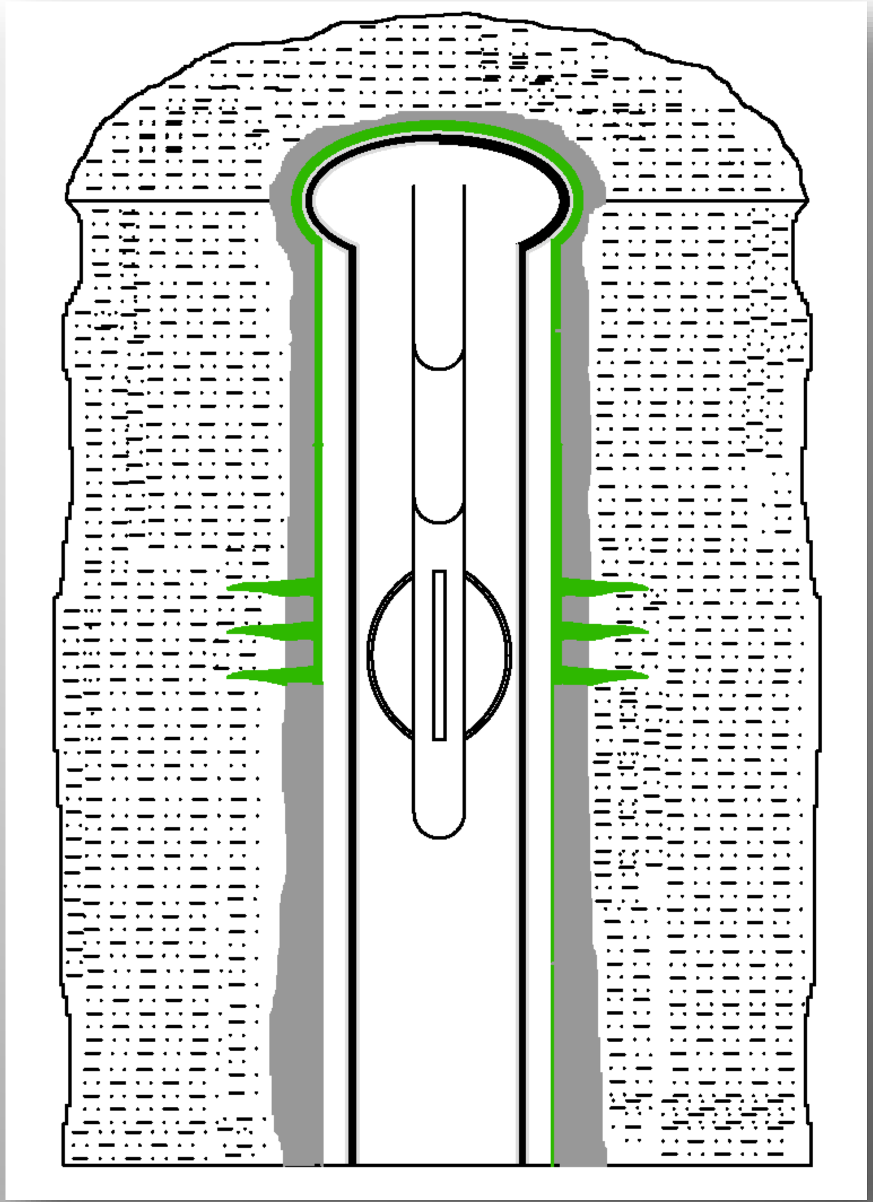
- A variety of cements ranging from lightweight to very heavy/dense cements are used when cementing either production or injection wells.
- Cements like a 50/50 Poz blend, although common, may reflect a different signal signature than cements of greater density and compressive strength.
- Additives may also impact signatures on cement evaluation logs.
- Understanding the cementing program is critical to the process of interpretation.

Log Calibration Challenges

- Calibration is key in the use of cement evaluation logs.
- Common technique involves finding an area of “free pipe” to calibrate the logging tool under a known wellbore condition.
- Lack of a distinct free pipe area in which to perform calibration may result in a log that is overly pessimistic.
- Logs generated using alternative calibration methods, in essence, reflect how the Logging Engineer set the log calibrations and may misrepresent cement presence and bond quality.
- Calibrating the logging tool is further complicated when gas is present inside the well.

Prior Well Activities

- When assessing cement through the use of cement evaluation logs, lots of details matter.
  - Workovers that have changed the configuration of the well.
  - Squeeze work for various purposes
  - Casing packers
  - Etc.
- Prior well activities may significantly complicate both the planning and evaluation process.
- Understanding prior well activities is crucial to planning logging for purposes of evaluating cement.



Source: All Consulting, 2015

TEMPERATURE & NOISE LOGGING

Temperature/Noise Logging

- Temperature & noise logging, in association with cement evaluation type logging, is likely the most useful when attempting to assess gas movement behind pipe .
- Effective T/A logging requires planning and well preparation.
- T/A logging should be complimented by other information (e.g., vent rate, RCBL, etc.).
- T/A logs can be used to confirm well integrity relative to gas movement behind pipe.
- T/A logging can confirm the general source (e.g., producing zone versus shallower interval)

Temperature Logging

- Temperature logging is one of the most basic logging tools used for downhole evaluations.
- Temperature logs are routinely used in the UIC program for assessing EWI, confirming injected waste is arriving and staying in the permitted injection zone, assessing wells for remedial workovers, and more.
- Temperature logging not limited for use by the oil & gas industry or for injection wells.


COMMONWEALTH OF KENTUCKY

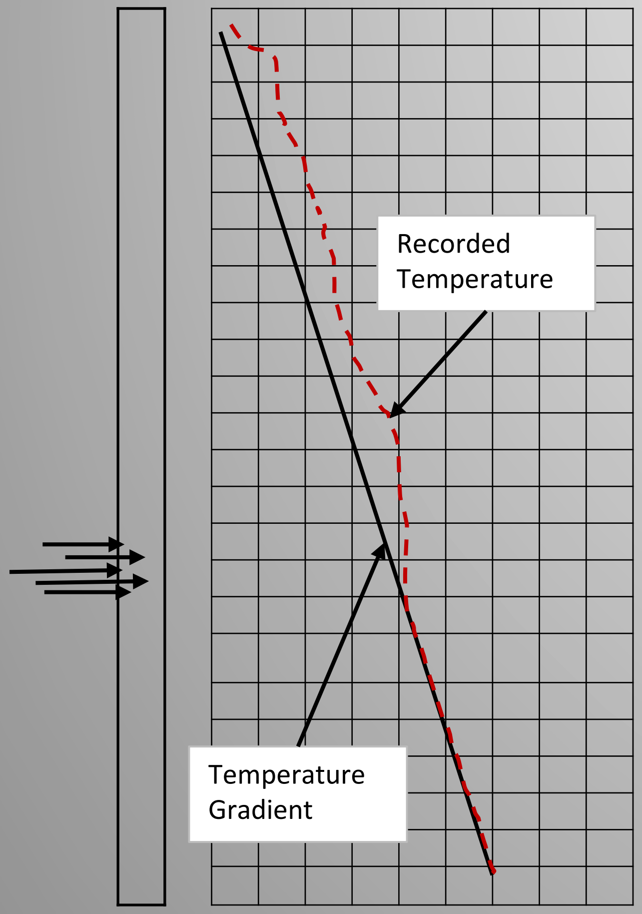
CLASS II INJECTION WELL OPERATOR'S MANUAL

Prepared by:
Division of Oil and Gas
Division of Water
U.S. Environmental Protection Agency
Representatives of the Oil and Gas Industry

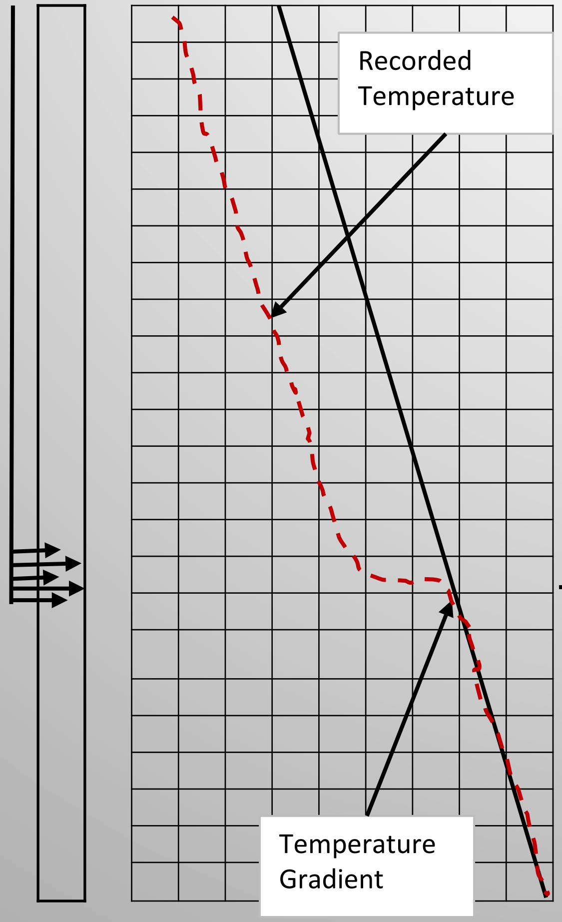
UNDERGROUND INJECTION CONTROL PROGRAM
AS ADMINISTERED BY
EPA United States Environmental Protection Agency

Temperature Log Interpretation

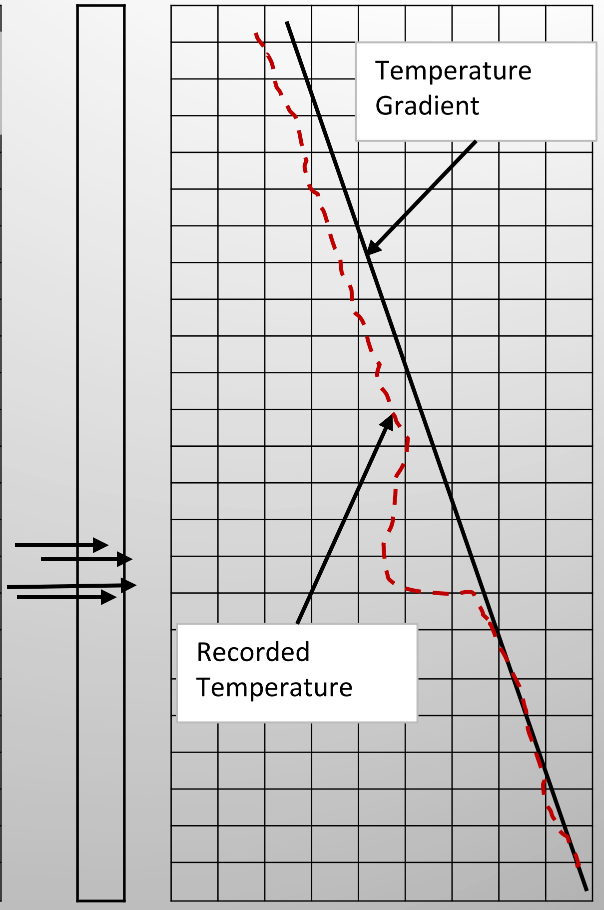
Fluid Entrance from Formation



Fluid Entrance & Downward Fluid Movement

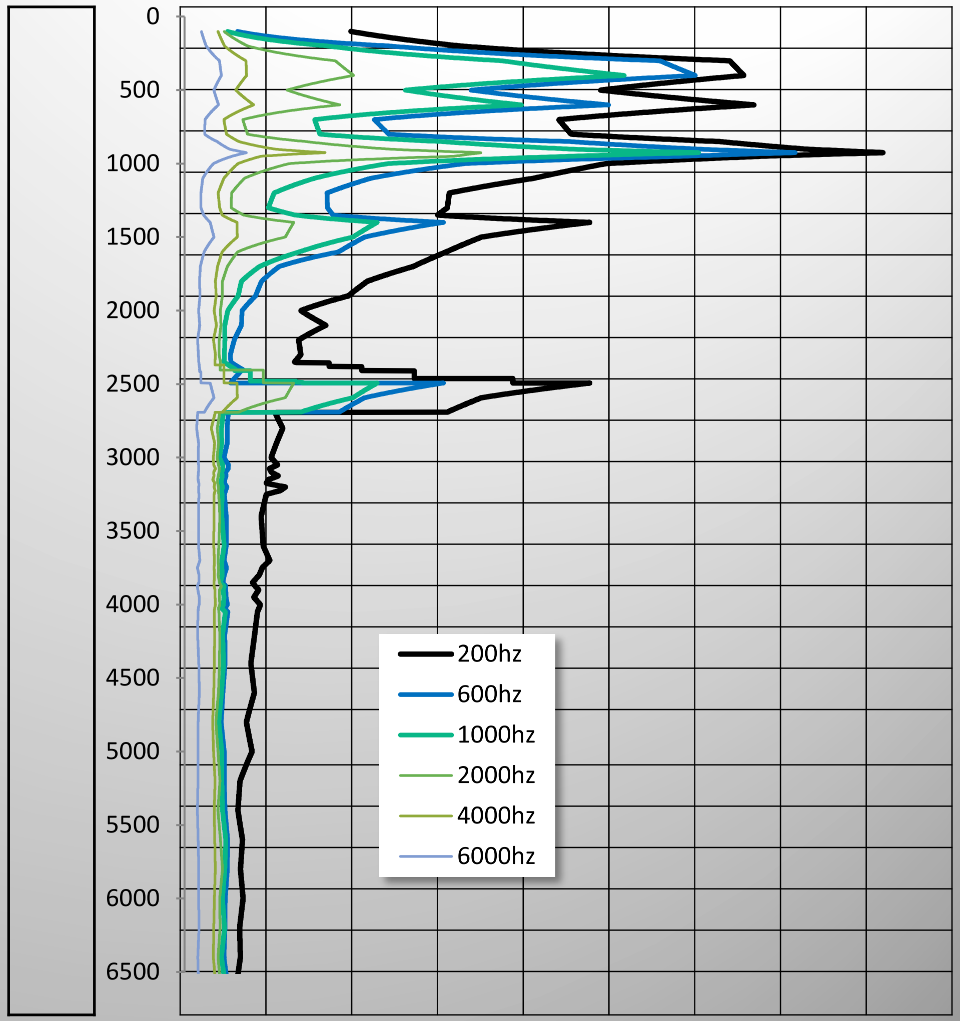


Gas Intrusion



Noise Logging

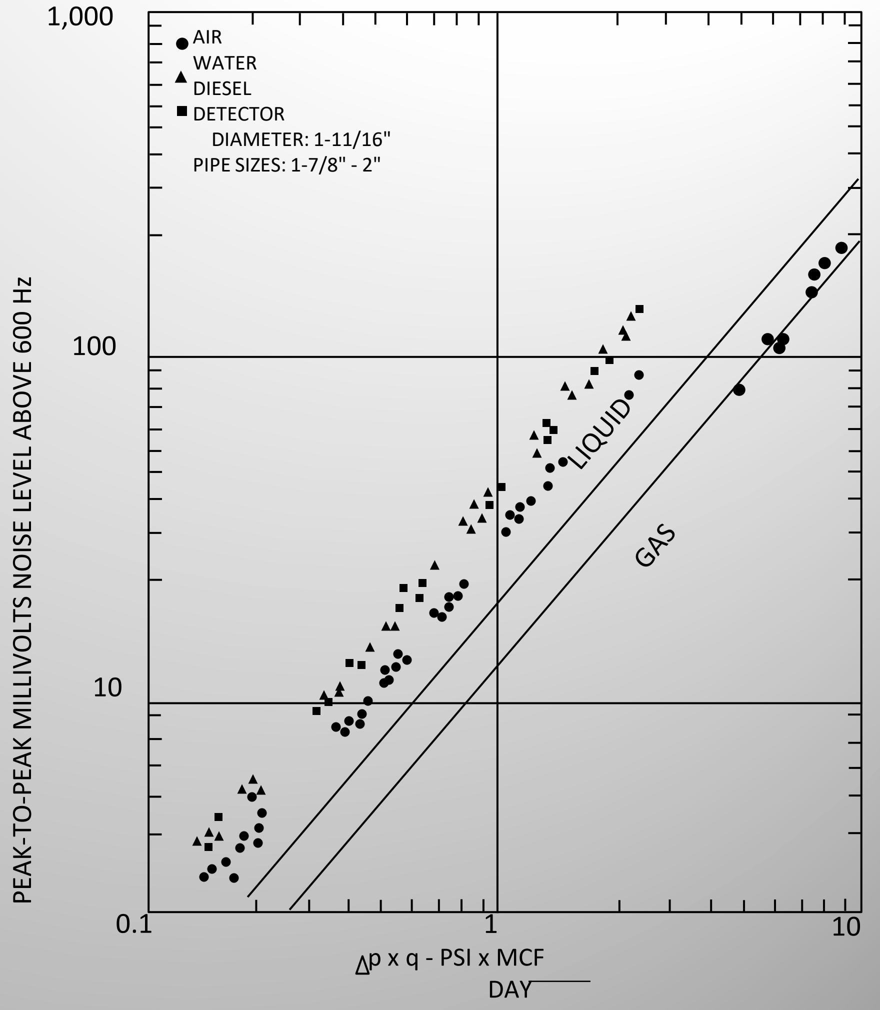
- First described by Arco in ~1955 as a "quantitative " tool, but utility was questionable.
- In 1973, Dr. McKinley (Exxon) started pointing out the utility of noise logging and ultimately worked with EPA and published a document on MI.
- For identification of gas movement behind pipe, noise logging can be crucial.
- Typically run with a temperature log and interpreted using other logs and data for the subject well.
- Unfortunately, interpretation is not commonly as straightforward as you might think!



Stray Gas and Noise Logging

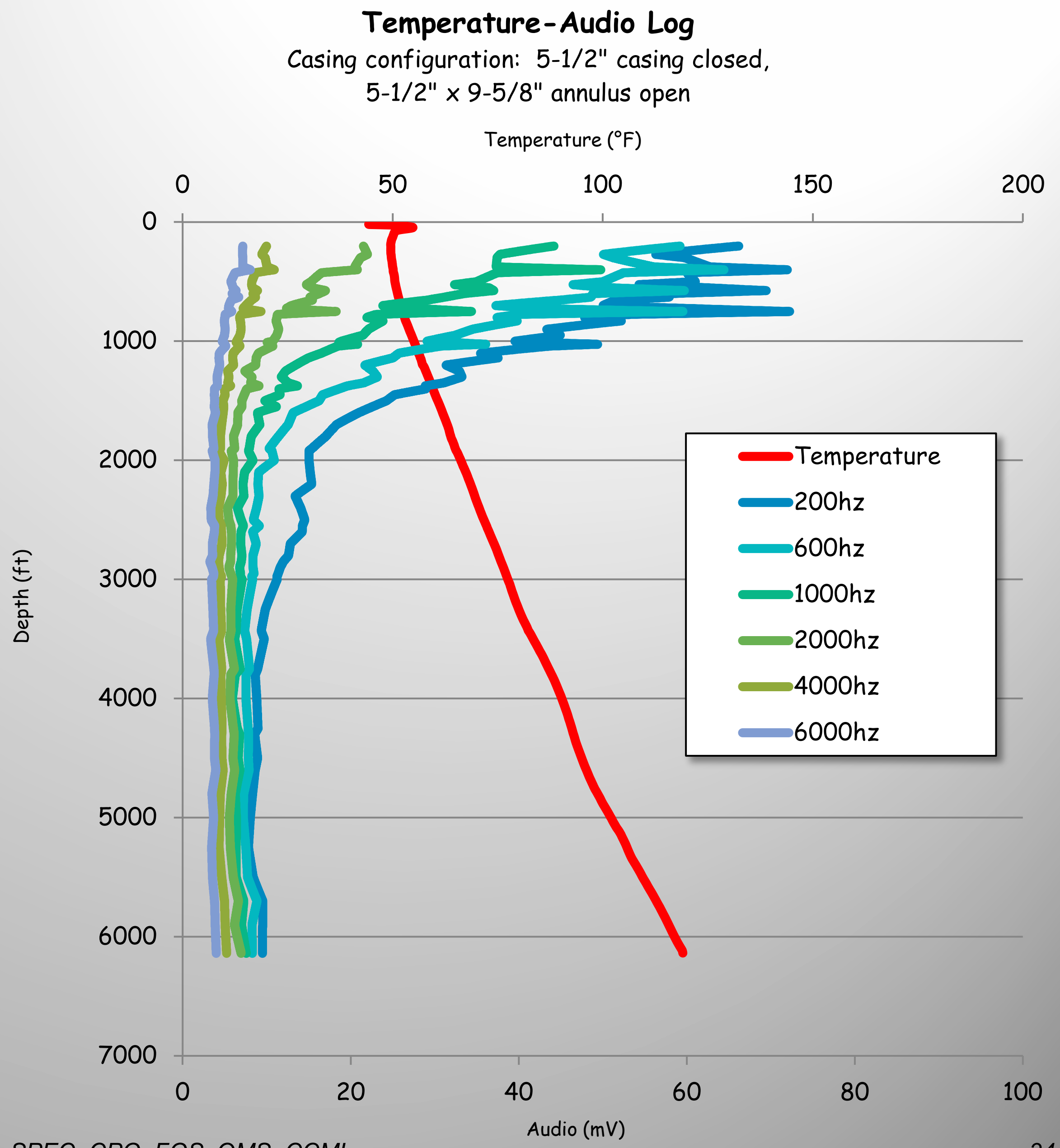
- When evaluating gas movement behind pipe opposed to liquid, audio analysis is a fundamental tool.
- As McKinley documented in 1979, gas movement makes more noise than liquid movement past a detector.
- Although noise logging can be used to assess liquid movement behind pipe, it is ideal for assessing gas movement!

Fig. 2 – Noise level generated by flow past a detector.



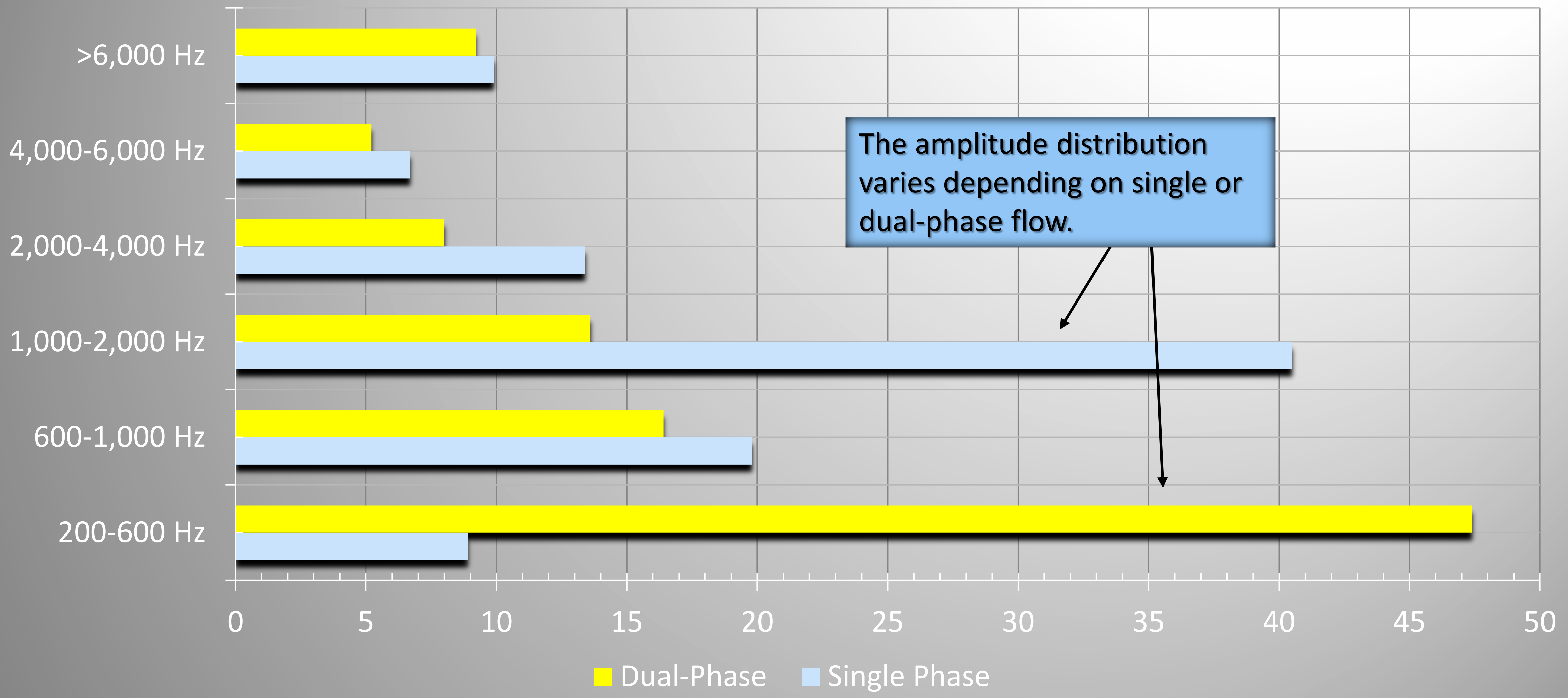
Noise/Audio Logs

Frequency Cuts	Significance
Below 200 Hz	• Noise in the range from 10 Hz to 100 Hz generally accounts for mechanical or surface noise including cable vibrations caused by the motors of logging trucks, by lubricator motion, and other surface disturbances
200 Hz – 600 Hz	• Eliminates most surface noise while still being low enough to detect the action of gas moving upward through liquid (*McKinley, Bowler and Rumble, 1973*). • Discrete bubbling – reflected by a spectrum peak in the 300 to 600 Hz range (*McKinley, Bowler and Rumble, 1973*) • Mild Slugging – spectrum peak above 200 Hz decreases with only a slight indication of bubble peak, (*McKinley, Bowler and Rumble, 1973*) • Severe Slugging - more energy is transferred into a band around 200 Hz. (*McKinley, Bowler and Rumble, 1973*) • Above 200 Hz, channel type leaks exhibit the same frequency structure as does free-stream, grid-generated turbulence (*McKinley, Bowler and Rumble ,1973*).
1,000 Hz – 2,000 Hz	• Noise spectra show presence of free-stream turbulence which is characteristic of single-phase flow (*McKinley, Bowler and Rumble, 1973*). • Above 1,000 Hz two-phase leaks are indiscernible from single-phase leaks (*McKinley, Bowler and Rumble, 1973*).



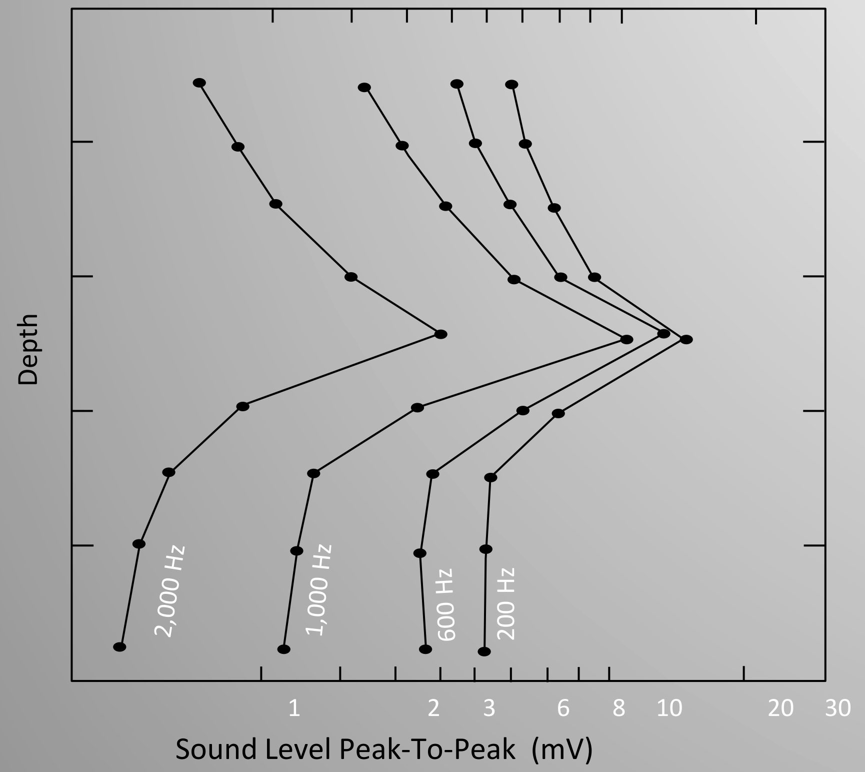
Prepared by: J. Daniel Arthur, P.E., SPEC, CPG, FGS, QMS, CCML

Typical Noise Distribution

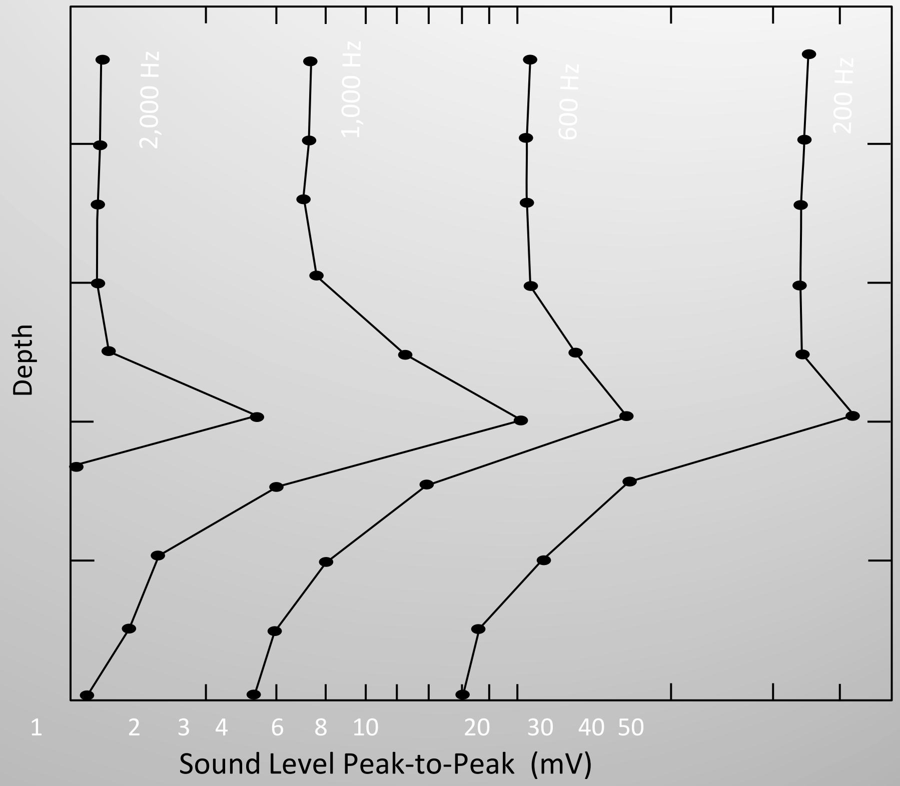


Single v. Dual Phase Flow

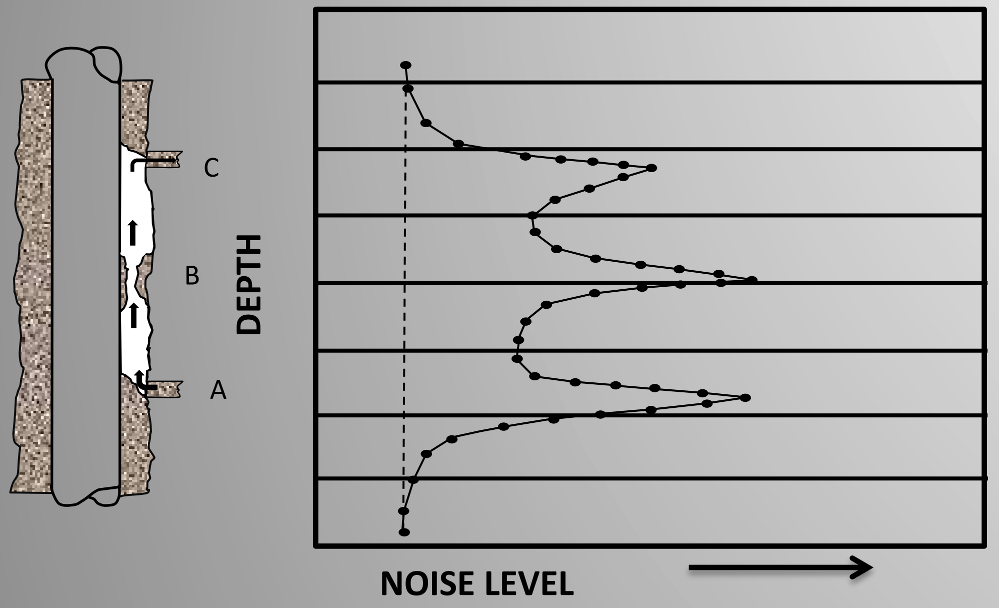
Noise Log characteristics of single phase leak

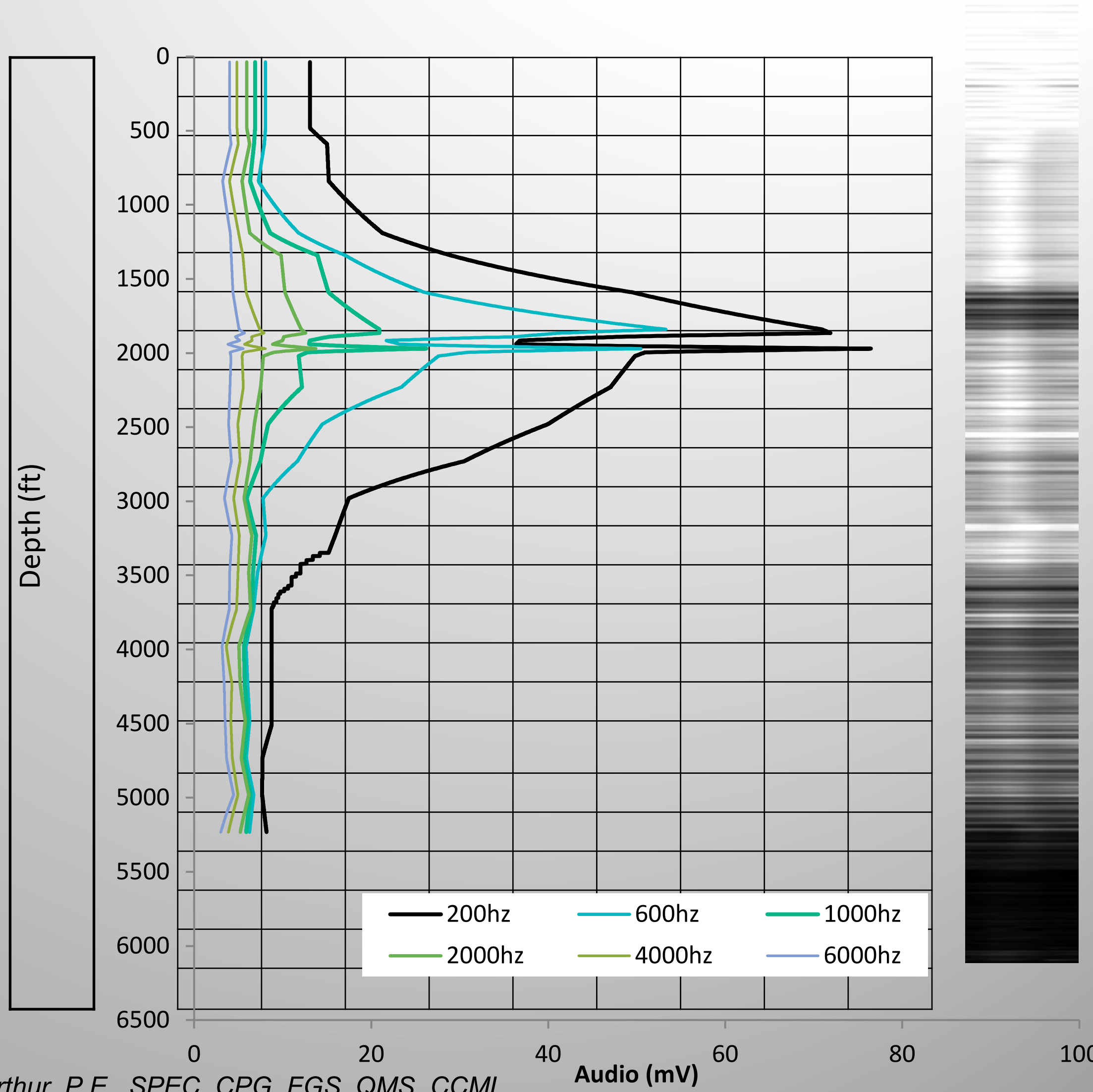


Noise Log characteristics of a gas-liquid, two phase leak



Restrictions and Two-Phase Flow

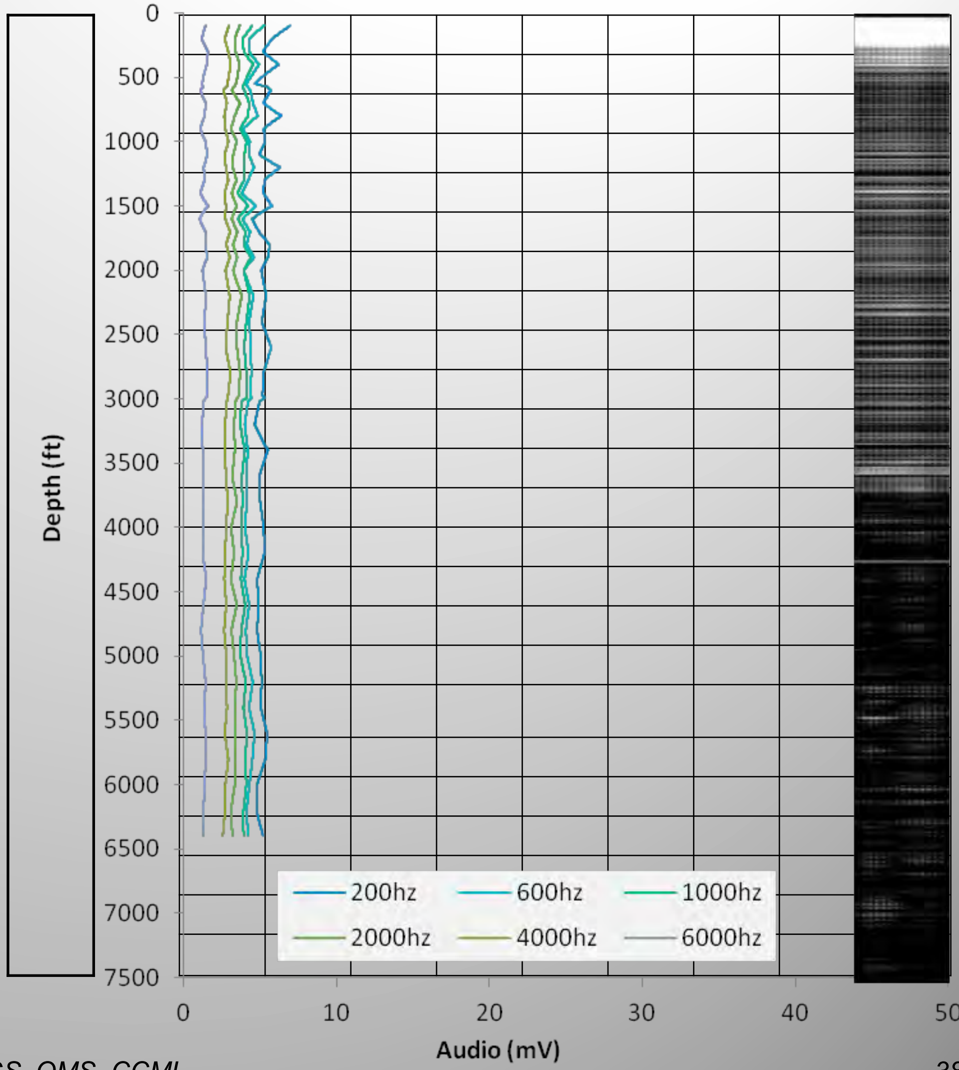




***NOTE**: the example above is from McKinley (1973) and although a great example, actual conditions can vary. The example to the right shows two-phase flow and a restriction as evident from the RCBL.*

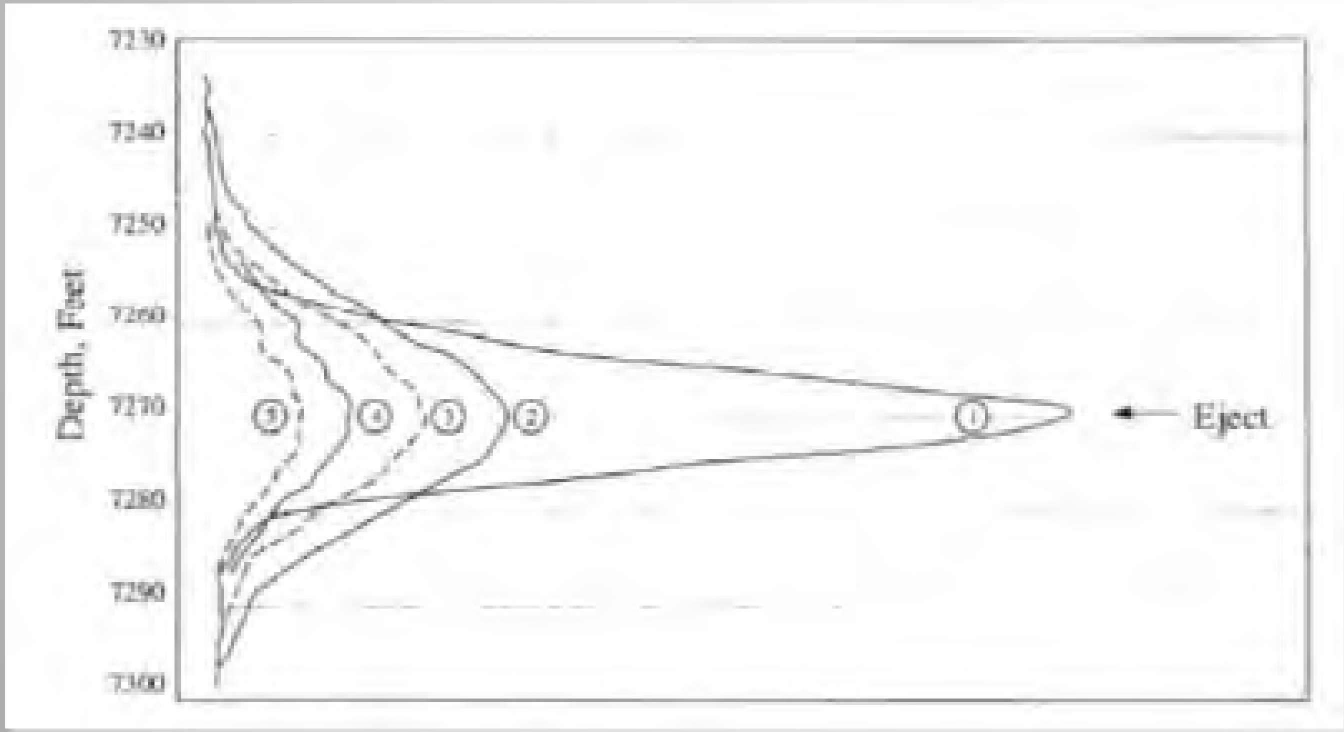
Noise Log with RCBL

- Noise logging rarely yields ideal results.
- Even with good cement, audio amplitudes within the 30 mV range are common.
- However, sometimes a near perfect log is obtained. This example also is void of near surface disturbance, which is common with noise logging (i.e., increase noise activity in the upper 500’).
- Remember that noise logs, like most logs, have settings controlled by the logging engineer and so logs can vary based on factors other than EWI.



QC for T/A Logging

- Logging practices must be standardized to ensure consistent results.
- The well must be properly prepared prior to logging.
  - Production tubing should be removed.
  - All casing and annuli <u>must</u> be completely fluid filled.
  - Wellbore should be refilled, if needed, after completion of temperature log.
  - The well must be allowed to stabilize for a minimum of 12 to 24 hours.
- Well must be configure properly to ensure intended results are achieved.
- Logs should be completed in sets to evaluate gas flow under varying wellbore conditions.
  - Production casing closed & surface casing open: Intended to induce flow in annular space(s) to identify and characterize flow.
  - Production casing open & surface casing closed: Intended to evaluate whether or not flow, if occurring, is exiting the wellbore.



Source: McKinley, 1994

RADIOACTIVE TRACER SURVEYS

Radioactive Tracer Survey (RTS)

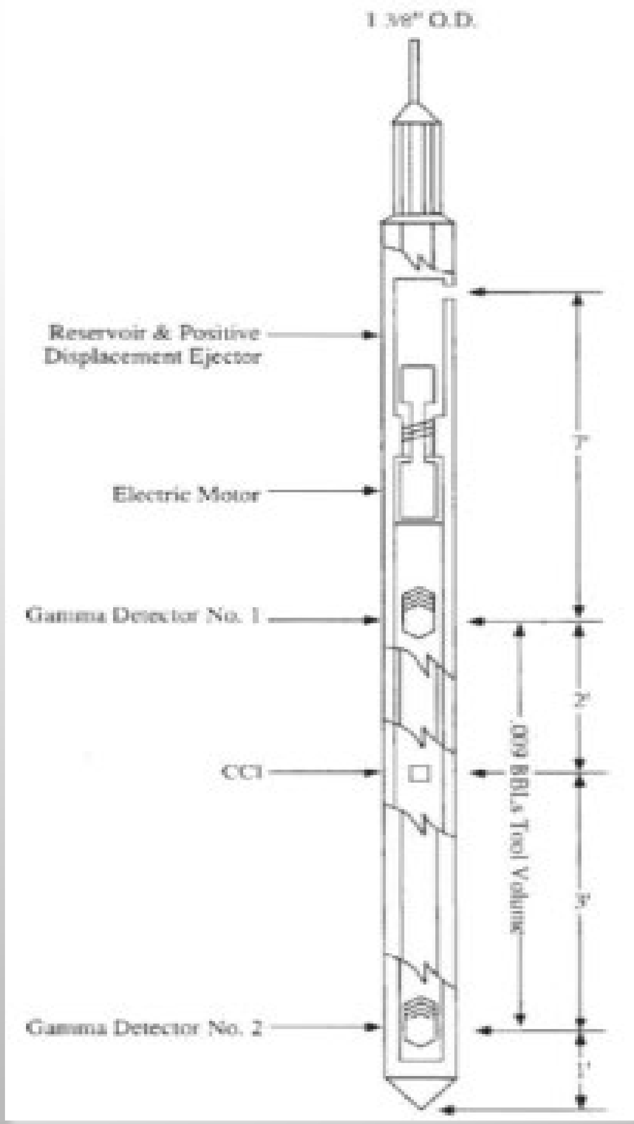
- An RTS is commonly used to test the mechanical integrity of the well
- The RTS detects the movement of the tracer fluid
- If mechanical integrity is compromised (tracer fluid is observed to split and travel in different directions), the test must identify the upward limit (i.e., shallowest well depth) of tracer fluid movement
- The RTS is run during active injection
- Typically set detector sensitivity low
- Prior to running the injection test a base log should be run to determine the baseline Gamma response of the formation
- Two different RTS procedures include Slug Tracking and Velocity Shot

Source: ALL Consulting, 2018

Radioactive Tracer Survey Tool

- Two basic parts to the RTS tool:
  - Top – reservoir and pump to deploy the tracer
  - Bottom – one or two GR detectors
    - Tools with Geiger counter sensors:
    - Tools with scintillation crystals;
    - Both tool types in current use
  - Casing collar locater often placed in between the two GR detectors
  - A temperature sensor often included in the tool assembly
  - Components of the tool may be rearranged
- The GR tool has a limited depth of investigation - 90% of gamma rays detected by the GR tool originate within one foot of the tool

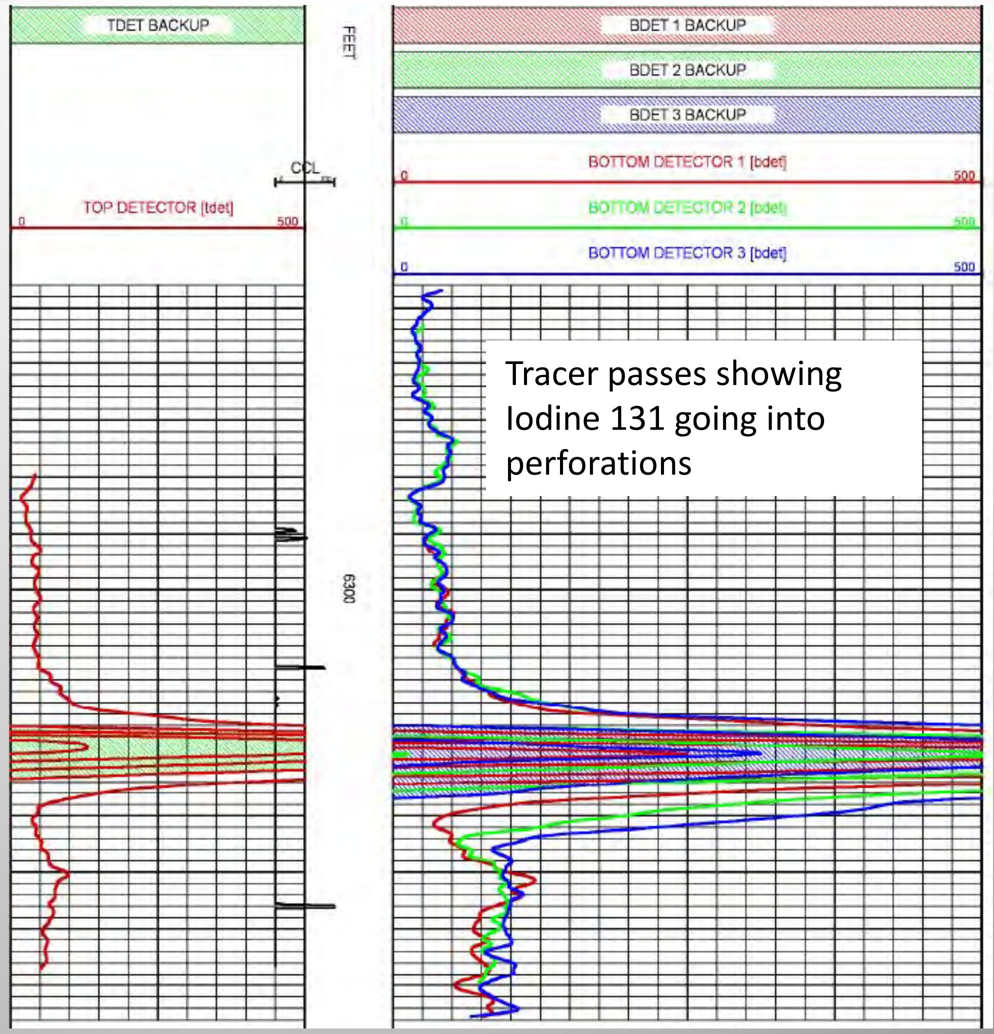
Typical RTS Tool



Source: McKinley, 1994

Radioactive Tracer Survey

- Radioactive material (most commonly Iodine^{131}) is used to tag field brine
- I^{131} has a half-life of 8.05 days
- Because of its negative charge, I^{131} is not usually strongly adsorbed to the formation surface
- The tagged brine is injected near the zone of interest
  - A typical shot is approximately 1/100th of the tool reservoir volume
  - A typical shot contains approximately 0.05 microcuries of I^{131}
  - Equal to approximately 1,500 times typical GR background

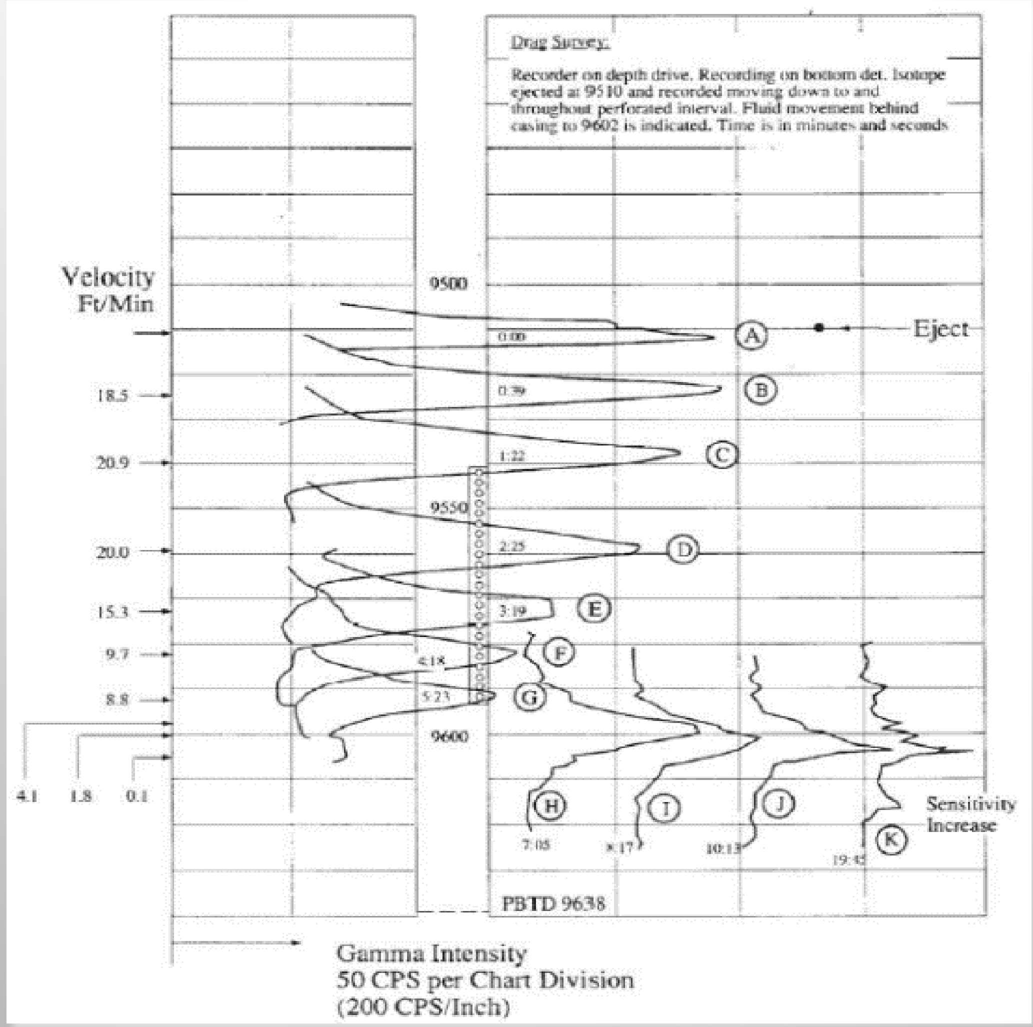


Source: ALL Consulting, 2018

RTS Slug Tracking Procedure

- Eject shot (slug) of tracer fluid above zone of interest
- Run RTS tool at timed intervals to observe movement of tracer fluid
- In this example:
  - Most fluid enters formation through perforations from ~9,560 to ~9,593
  - Some tracer observed below perforations
  - Second slug released at 9,604 feet –logged, did not show movement (not shown on this display)
  - Therefore, flow of tracer below the bottom perforation (logging runs H-K) observed occurring behind the casing

Example Drag Survey

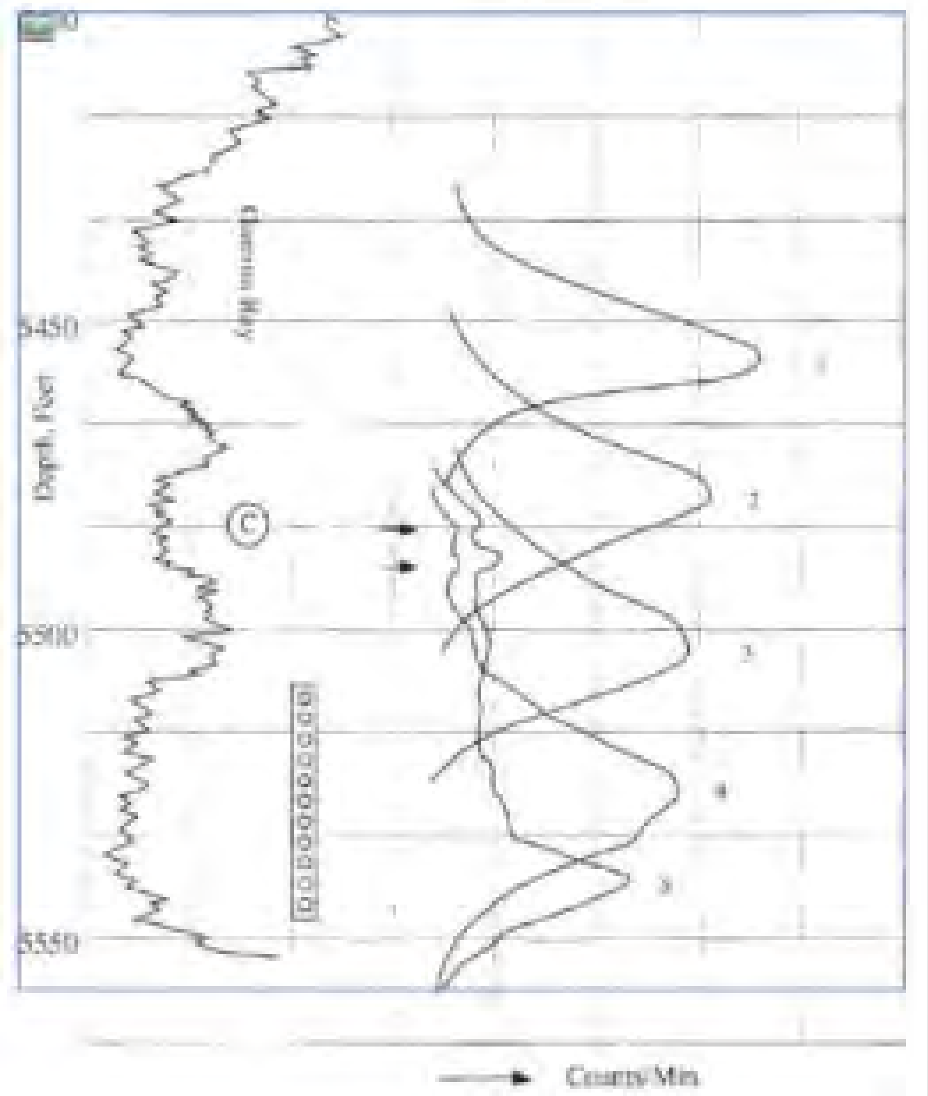


Source: McKinley, 1994

Example Slug Tracking for Flow Behind Pipe

- Set detector sensitivity to 200 API units/inch
- Can run either slug tracking or stationary velocity surveys
- Slug tracking:
  - First check for loss behind pipe from uppermost perforations
  - Run background GR log before ejecting slug
  - Eject tracer slug ~20 feet above top perf
  - Run successive logs at same sensitivity as background log
  - After tracer logs are run, rerun background GR log as QA/QC check
  - Look for tracer that has split off from the main slug and migrated back uphole as an indication of flow behind pipe (see runs 4 and 5)

Arrows indicate Flow Behind Pipe



Source: McKinley, 1994

RTS CRITICALITIES

- Best suited to injection wells (single phase), not as commonly used in producing wells
- Tool configuration may be modified to suit the specific use
- The well should be stable (~72 hours at a stable flow rate) prior to logging
- Best if tool is centralized
- RA fluid must be soluble in or neutrally buoyant in the well fluids
- Baseline GR should be run prior to the RTS and final baseline run after ejection of all tracer slugs.
- Ejection times from shot to shot should be consistent
- Open hole wellbore must also have a caliper survey run for flow profiling

- **Downhole video logging can be an additional tool utilized for well integrity**
- **Used in combination with other tools to assess well integrity issues**

Source: DMRM, 2010

DOWNHOLE VIDEO LOGGING

Questions?

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