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Theme 3: Mechanical Integrity

Pre & Post Well Integrity Methods for Hydraulically Fractured/Stimulated Wells

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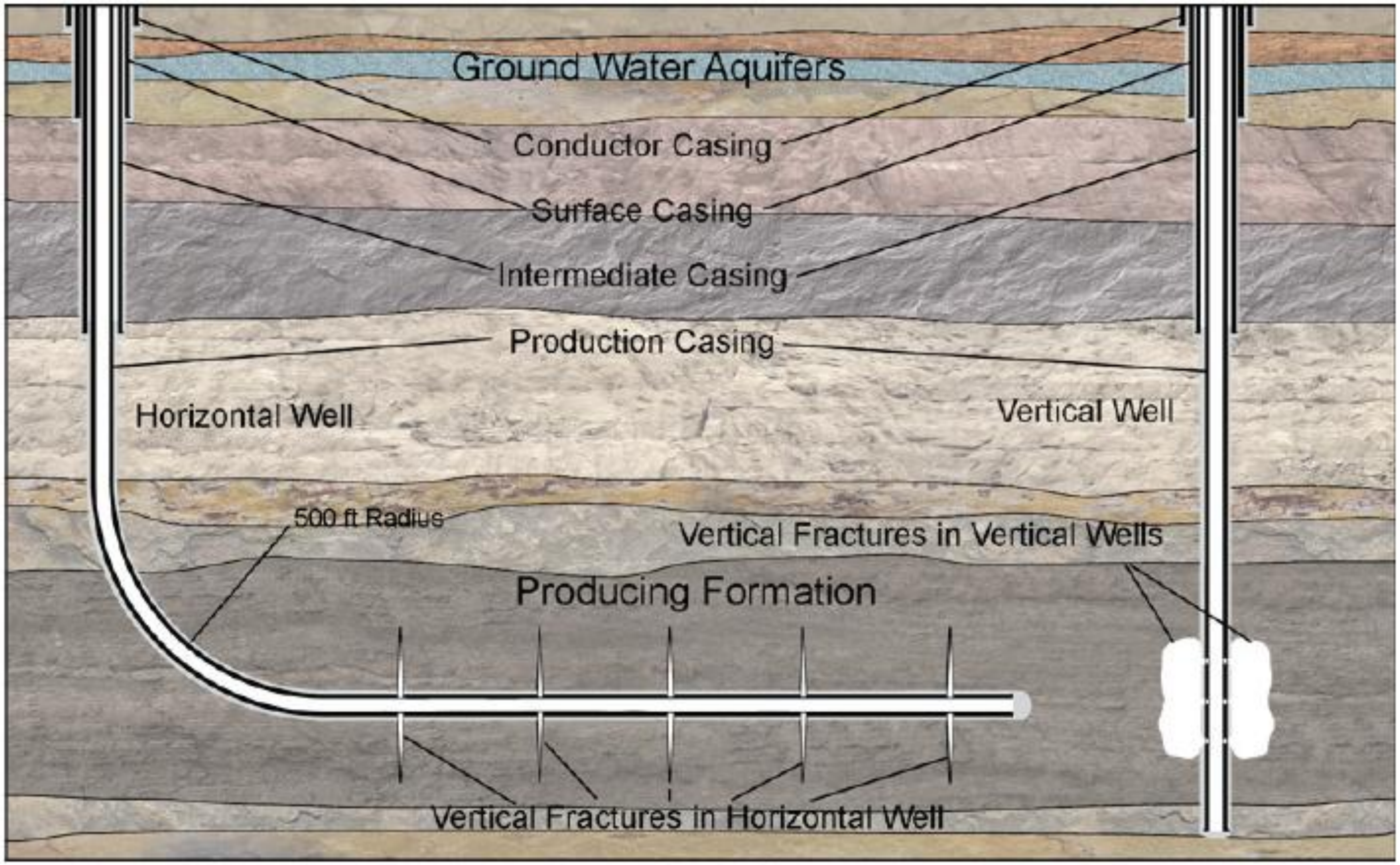


Figure 3—Example of a Horizontal and Vertical Well

Courtesy, API 2009

Casing Setting and Design

- NORSOK 2004 lists factors to consider in casing design

  - Casing must be designed to withstand tensile, burst and collapse loads

  - Use safety factors (wear and tear) for casing deterioration

  - Axial and bending forces and shock load

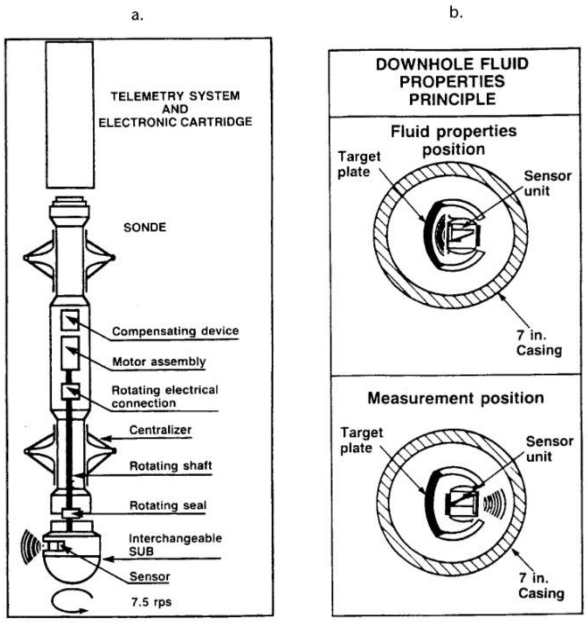
  - Casing design should also consider buckling, piston and thermal effects
- For refracturing candidates, eliminate any well as a candidate if there is any indication of gas migration to surface

Cementing Systems for Production/Injection Wells

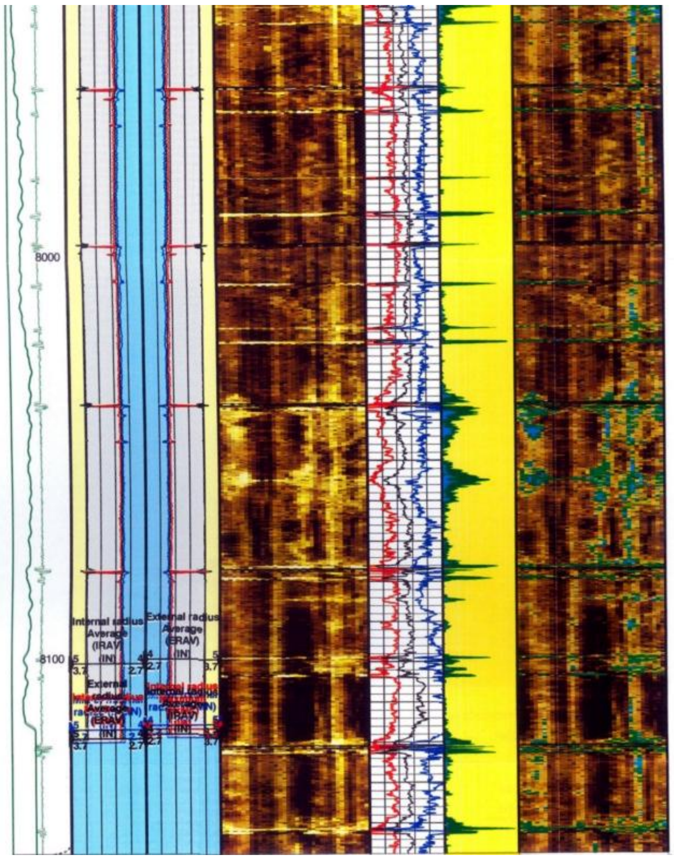
- Portland cements generally used for oilfield service
- Use of non-Portland specialty cements need additional steps in planning and execution phases
- Quality of the cementing operation critical for wellbore integrity – thoroughly circulate, effects of well deviation, use centralizers, SCP (sustained casing pressures) and causes
- Potential pathways for escape of fluids up-hole

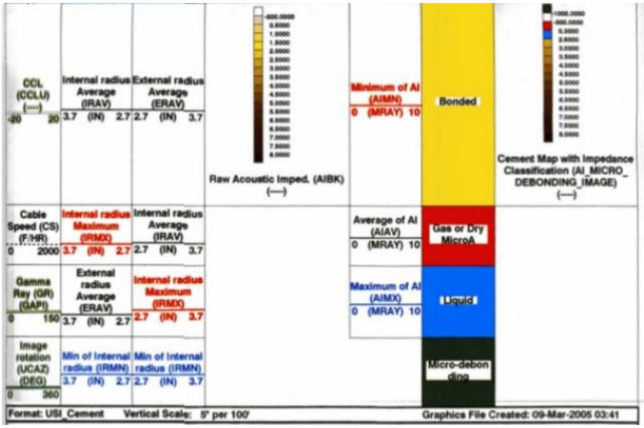
Cement Evaluation

- Two classes of sonic logging tools: (1) sonic (CBL/VDL) or SBT and (2) ultrasonic (USIT/CAST-V)
- Acoustic cement bond logs do not measure hydraulic seal but instead measure loss of acoustic energy as it propagates through casing. This loss of energy is related to the fraction of casing perimeter covered by cement
- The Ultrasonic Imaging Tool (USIT) is a continuously rotating pulse-echo type tool with nearly 100% coverage of the casing wall. The transducer ("sensor") rotates, emitting and receiving signals reflected back from the casing wall. Preferable to run CBL with it for overall well integrity picture
- The Segmented Bond Tool (SBT) measures the quality of cement effectiveness, vertically and laterally around the circumference of the casing. The SBT measures 6 segments around the pipe and uses high frequency steered transducers mounted on 6 pads. Each of 6 motorized arms positions a transducer and receiver against the casing wall. SBT is usually run with VDL

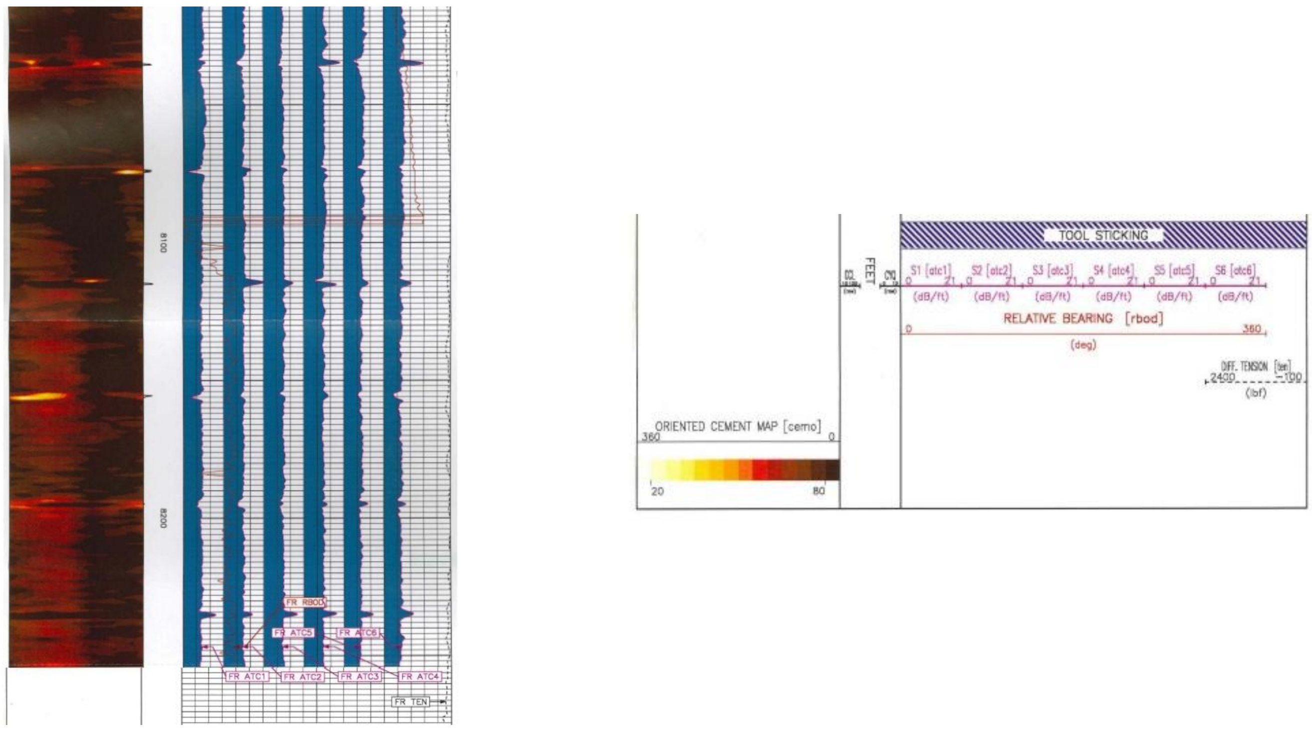


Ultrasonic Imager (a) tool design and (b) transducer position (Smolen, 1996)





Example USIT Log



Example SBT/VDL log

Factors that Affect Cement Log Quality

- Micro-annulus, eccentralization, logging tool centralization, fast formations, lightweight cement, and cement setting time

- Good practice to pressure test the shoe after drilling out the surface and long string casing strings (FIT) and confirm zonal isolation at the casing shoe

Wellbore/Mechanical Integrity Methods

- Internal MIT – Pressure test
- External MIT – confirm all fluids contained within wellbore and no upward flow behind casing, cement evaluation as discussed earlier – USIT/SBT-VDL/CAST-V and quality of cement job. Use of fluid confinement/channel logs: OA/WFL, RTS, Borax PNL, Temperature, Carbon Oxygen (CO)
- Pressure tests at casing shoe (FIT/LOT/CIT) to verify zonal isolation
- Multi-finger caliper (MIT) surveys and magnetic thickness tools (MTT) to assess both internal and external condition of the tubular from corrosion and/or erosion impacts

Zonal Isolation and Casing Shoe Integrity

- Placement of cement completely around the casing and at the proper height (cement top) above the casing shoe is critical in achieving zone isolation and integrity

- Pressure tests to verify isolation at casing shoe include Formation Integrity Tests (FIT) (also called LOT – leakoff test) and Casing Integrity Tests (CIT). Pressure up inside the casing until pressure at shoe exceeds the maximum hydrostatic pressure expected at that point during subsequent drilling operations. Failure at shoe is usually due to contamination (from either original drilling mud or from displacement fluid) and is a result of poor cementing techniques rather than poor quality cements

Oxygen Activation/Water Flow Log/ Hydrolog/Spectra Flow Log

- Used to detect water flow or channels behind casing
- WFL is a dual burst TDT with a modified pulse sequence
- The WFL measurement technique and a WFL run on an injection well is shown.

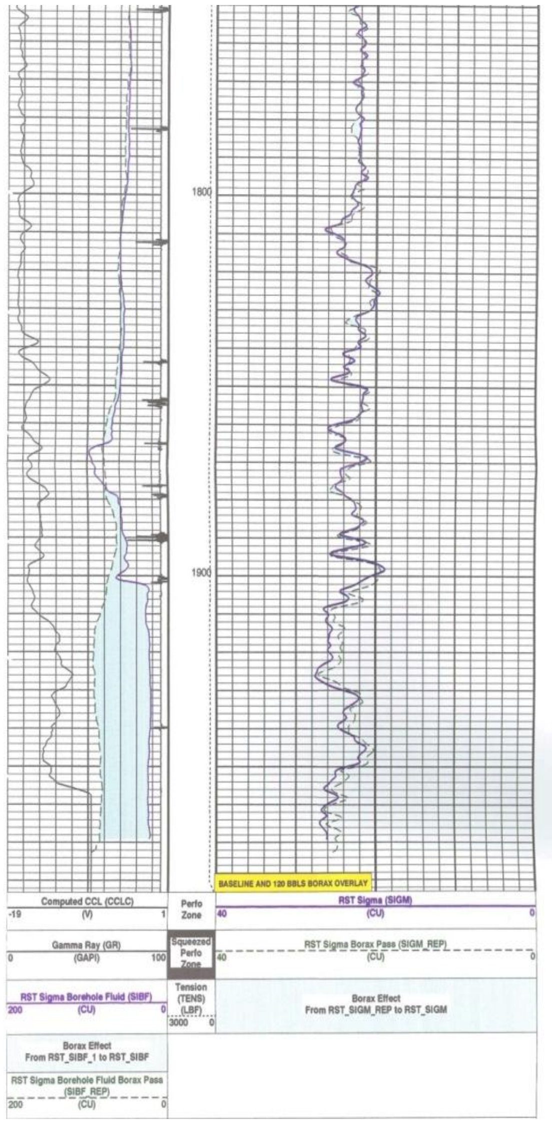
Borax- PNL *Log*

- Compares passes run before and after pumping a borax solution dissolved in warm water. A PNL indicates a significant Sigma value when boron is present. An example log run in Alaska is shown.

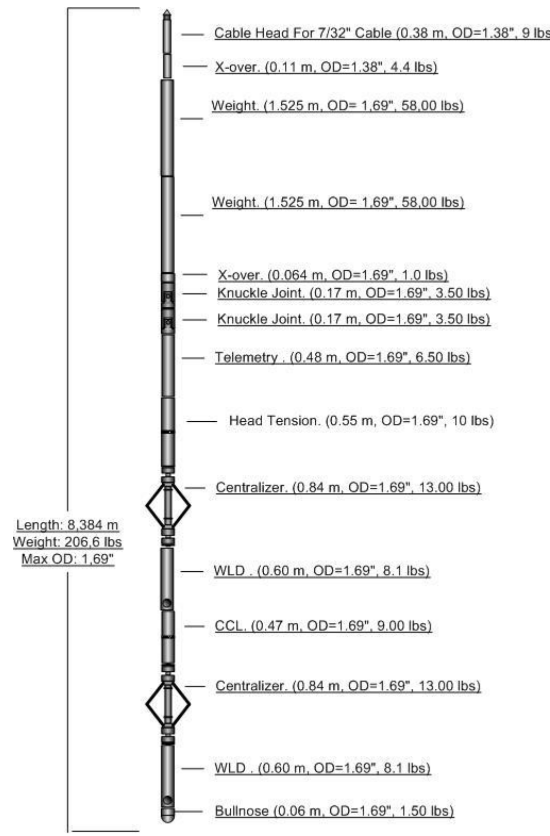
Ultrasonic Leak Detection Logs

- Can detect very small leaks, through multiple strings and can be run on wire-line or on slick-line in memory mode.

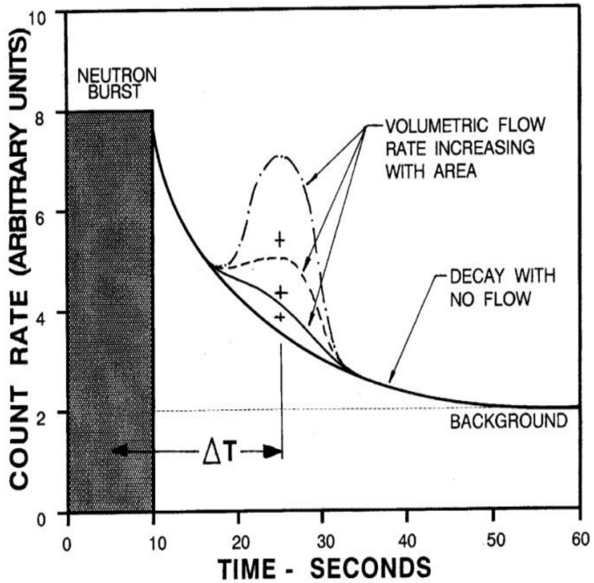
Example Borax-PNL Log



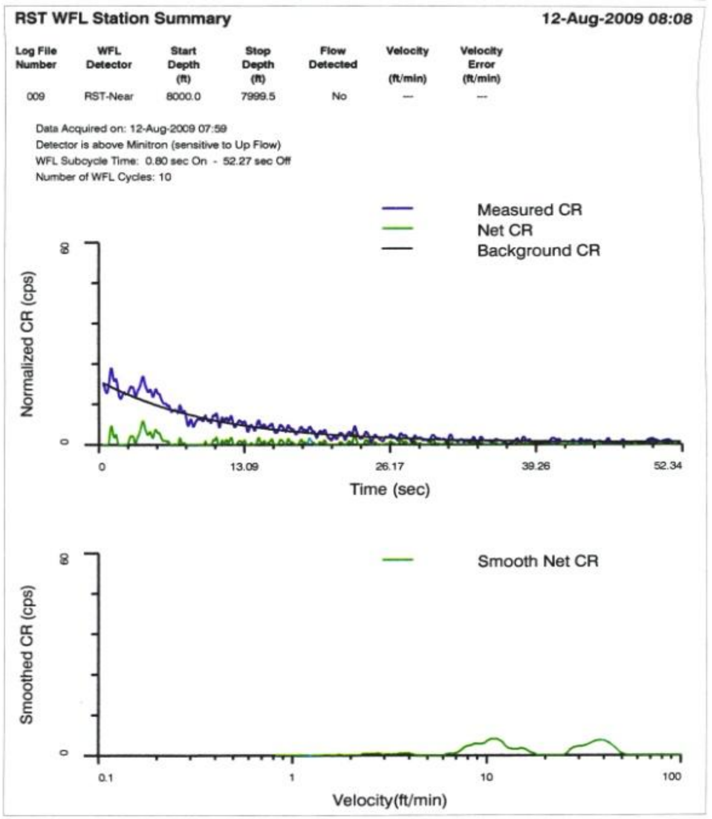
Ultrasonic Leak Detection Tool Configuration



WLD toolsketch



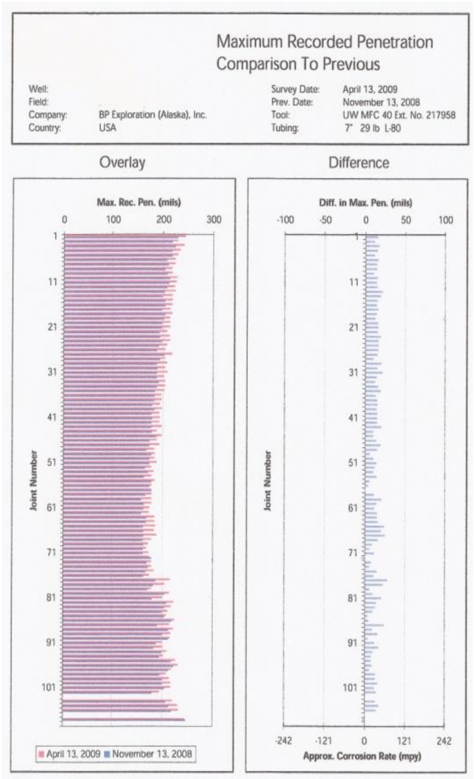
WFL/OA Log Measurement Technique (Smolen, 1996)



WFL Run on Injection Well

Magnetic Thickness Tool (MTT)

Multi-finger Imaging Tool (MIT)



Example of Multi-Finger Caliper Survey

Thank You

Questions?

Pre and Post Well Integrity Methods for Hydraulically Fractured/Stimulated Wells

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Wellbore integrity is important to ensuring that reservoir formation fluids are brought to the surface in a controlled and safe manner, and do not migrate into overlying fresh water aquifers/underground sources of drinking water (USDWs). This paper will look into wellbore design and monitoring techniques that are critical in assuring that wellbore integrity is maintained in conjunction with hydraulic fracturing/stimulation completion practices.

The subsurface zone or formation containing hydrocarbons produces into the well, and that production is contained within the well all the way to the surface. This containment is what is meant by the term “well integrity”. NORSOK D-010 defines well integrity as “Application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life-cycle of a well”. Wellbore integrity as related to hydraulic fracturing can be divided into three areas: pre-hydraulic fracturing design and completion aspects to ensure wellbore integrity; techniques to verify that wellbore integrity is maintained post-hydraulic fracturing; and the potential impact on long-term wellbore integrity (casing and cement) from re-fracturing stimulations.

Well Design and Construction

Casing Setting and Design

As is required in all engineering designs, surface equipment and down-hole tubular are designed for the anticipated operating pressures. This design requirement results in the proper selection of appropriate casing and tubing grade and weight to avoid wellbore collapse. There is a higher risk of compromising the casing integrity during drilling operations. The following points should be considered in casing design (NORSOK 2004):

- Planned well trajectory and bending stresses induced by doglegs and curvature
- Maximum allowable setting depth with regards to kick margin
- Estimated pore pressure development
- Estimated formation strength
- Estimated temperature gradient
- Drilling fluids and cement program
- Estimated casing wear
- Setting depth restrictions due to formation evaluation requirements
- Isolation of weak formations, potential loss circulation zones, sloughing and caving

- Metallurgical considerations
- Potential for H_2S and CO_2
- Equivalent circulating density (ECD) and surge/swab effects due to narrow clearances
- Geo-tectonic forces applicable

The casing is exposed to different loading conditions during various well operations (landing, cementing, drilling, production). It has to be designed to withstand tensile, burst, and collapse loads. Since it is impossible to predict the magnitude of these loads during the life of the casing, the design is based on a worst-case scenario. The casing rating also deteriorates with time (wear and tear). Therefore, safety factors are used to make sure that the casing could withstand expected loading conditions.

Collapse pressure is mainly due to the fluid pressure outside the casing (due to drilling fluid or cement slurry). Overpressure zones could also subject the casing to high collapse pressure. The casing's critical collapse strength is a function of its length, diameter, wall thickness, Poisson's Ratio etc. Burst loading is due to the fluid pressure inside the casing. Severe burst pressure occurs if there is a kick during drilling operations. The tensile stress originates from pipe weight, bending load and shock load. The axial force due to pipe weight is its weight in air less the buoyancy force. Bending force results when the casing is run in deviated wells where the upper portion of the casing is in tension and the lower portion is in compression. Shock load is generated by setting of the slips and application of hoisting brakes. The sudden stoppage when casing is run generates stress waves along the casing string.

In addition to the three loading conditions described above, casing design should also consider the likelihood of buckling, piston and thermal effects. Buckling results when the casing is unstable (e.g. partially cemented). The casing string will exhibit a helical configuration below the neutral point, resulting in rapid wear at the neutral point and eventually lead to casing failure. Piston force is due to the hydrostatic pressure acting on the internal and external shoulders of the casing string while thermal effects refer to the expansion or shortening of the casing due to increase or decrease in temperature.

Cementing the Casing/Liner

The quality of the cementing operation is also critical in maintaining wellbore integrity. Besides the selection of the proper cement systems, the placement of cement and the quality of the cement job are critical elements in assuring the well's integrity. It is very important to thoroughly circulate and clean out the well prior to cementing in order to prevent mud mixing into the cement, causing cavities or channels, resulting in potential cement degradation and/or creation of leakage pathways for the formation fluids.

Well deviation can also affect the quality and presence of the cement. Drilling mud is first circulated in the hole to ensure that drill cuttings and borehole wall cavings have been removed prior to running the casing. The mill varnish is also removed from the surface of the casing to ensure that the cement will bond to the steel surface. Centralizers are used to ensure that the casing is placed in the center of the borehole. For under-reamed or washed out holes, bow spring centralizers are used. After the cement slurry is pumped down-hole, a lighter drilling mud follows. This results in the casing being under compression from a higher differential pressure on the outside of the casing. Thus when the cement sets and drilling continues, the casing will always have an elastic load on the cement-casing interface, which is essential for maintenance of the casing-cement bond and to prevent channeling or micro-annulus effects in the cemented annulus.

Many wells are subject to sustained casing pressures (SCP). The main cause is believed to be gas flow through the cement matrix. The cementing problems that could result in SCP include: (1) micro-annuli caused by casing contraction and/or expansion, (2) channels caused by improper mud removal prior to and during cementing, (3) loss circulation of cement into fractured formations during cementing, (4) flow after cementing by failure to maintain an overbalance pressure, (5) mud cake leaks, and (6) tensile cracks in cement caused by temperature and pressure cycles (Sweatman, 2006).

Mechanical Integrity Methods for Production/Injection Wells

In the United States, every production and/or injection well is required to demonstrate that it has sound mechanical integrity prior to it being placed on production/injection. Statutes and regulations have been implemented in every state to ensure that oil and natural gas operations are conducted in a safe and environmentally responsible fashion and wellbore integrity is maintained throughout their operating life-cycle. The regulatory requirements for injection wells as codified under 40 Code of Federal Regulations (CFR) Parts 144 through 148 require that the injection well demonstrate that it has both internal mechanical integrity (no leaks in tubing/packer or casing) and external mechanical integrity (all injected fluids are exiting the permitted injection interval and that there is no upward migration behind pipe due to channeling or a bad cement job/micro-annulus etc.). Leakage out of the production/injection zone into overlying USDWs could occur due to poorly cemented casing, casing failure, improperly plugged and abandoned wells or other artificial conduits, and natural fractures/faults etc. Cement that has properly set has very low permeability (approximately 10^{-2} m^2) and no significant flow of formation fluids can occur unless the cement has degraded or has not set properly. Casing failure could occur due to corrosion, erosion or improper design (Syed et al, 2010)

Internal Mechanical Integrity

Throughout the life of a producing well and during fracturing operations, the well conditions should be monitored on an ongoing basis to ensure integrity of the well and well equipment. Maximum and minimum allowable annular surface pressures should be assigned to all annuli (should be considered as “do not exceed” limits). Also, during initial drilling completion, positive pressure tests of the casing, tubing and inner annulus (between tubing and casing above the packer) are conducted. The required surface test pressure varies in each geologic area (but is generally at least 0.25 psi/foot of vertical depth to the top of the packer and the inner casing and may not exceed 70% of the minimum yield strength of the casing). A well has verified its internal mechanical integrity if the total pressure loss within the test period is less than 10% of the initial test pressure and the pressure is stable (thermal stabilization effects). Thermal stabilization can occur when liquids either expand or contract depending on temperature differential, causing questionable test results. Pre-loading an annulus or using fluids that are close to the same temperature as fluids in the well will help in mitigating this effect. The test fluid is generally an inert non-corrosive fluid/water or in some instances it could be a 50-50 mix of methanol/water, neat methanol or diesel (used in extremely cold environments for freeze protection). Factors to consider when conducting such tests (also referred to as MITIA or SAPT – Standard Annulus Pressure Test), is that when a liquid medium is used as the test fluid, the well may pass the MITIA, but later when it is on gas injection, there may be slow annulus pressure build-up (sustained casing pressure) that may not be easily detected over a long period of time. Other factors to consider for a successful MITIA for wells include proper packer selection (elastomers) and materials of construction for tubing and surface wellhead that will meet production and/or injection service requirements.

External Mechanical Integrity

There are several techniques that can be utilized to verify that production fluids are contained within the wellbore and that there is no upward flow behind the casing (due to chanelling/micro-annulus etc.) that can impact overlying USDWs. Some of these techniques are briefly discussed below (Syed et al, 2010).

Cement Evaluation

Acoustic cement logs are run to determine cement tops as well as the quality of the casing-cement and cement-formation bonds. Acoustic bond logs do not measure hydraulic seal, but instead measure the loss of acoustic energy as it propagates through casing. This loss of energy

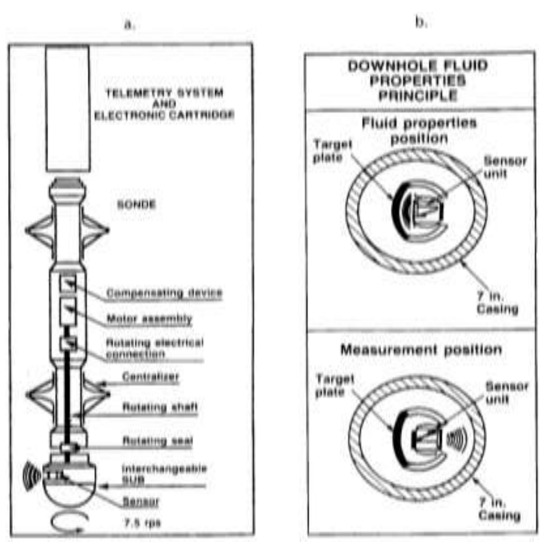


Figure 18. Ultrasonic Imager (a) tool design and (b) transducer position (Smolen, 1996)

is related to the fraction of the casing perimeter covered by cement. Two classes of sonic logging tools exist: (1) sonic (cement bond log/variable density log – CBL/VDL) or segmented bond tool (SBT) and (2) ultrasonic (ultrasonic imaging tool – USIT) (Boyd et al, 2006).

The Ultrasonic Imaging Tool (USIT) is basically a continuously rotating pulse echo type tool, and is an improvement over the Cement Evaluation Tool (CET) with nearly 100% coverage of the casing wall. The processing of the echo is, however, quite different from the CET. The USIT is shown schematically in Figure 18. The main working element is the rotating transducer indicated as "sensor" on the bottom of the tool string. The transducer rotates, emitting and receiving signals reflected back from the casing wall. The USIT tool is 3 3/8" in diameter and by changing the rotating transducer subassemblies can operate in casing sizes from 4 ½' to 13 3/8". The rotating transducer is shown in Figure 18(b). In the measurement position it is aimed toward the wall and in the fluid properties position it is aimed toward the target plate, with the fluid properties measured when going in the hole. The USIT presentation uses highly sophisticated computer processing and is color coded. It is very sensitive to the condition of the borehole and is preferably run along with a CBL to provide best overall picture of well integrity. An illustrative example of a USIT log is shown in Figure 19.

Acoustic impedance, Z, is defined as the product of the density (kg/m3) and acoustic velocity (m/sec) of a medium and is expressed in MRayl (10^6 kg/m^2 sec). A list of acoustic impedance values for common down-hole materials is given in Table 1Table 3.

Figure 19. Illustrative Example of USIT Log Run on Injection Well

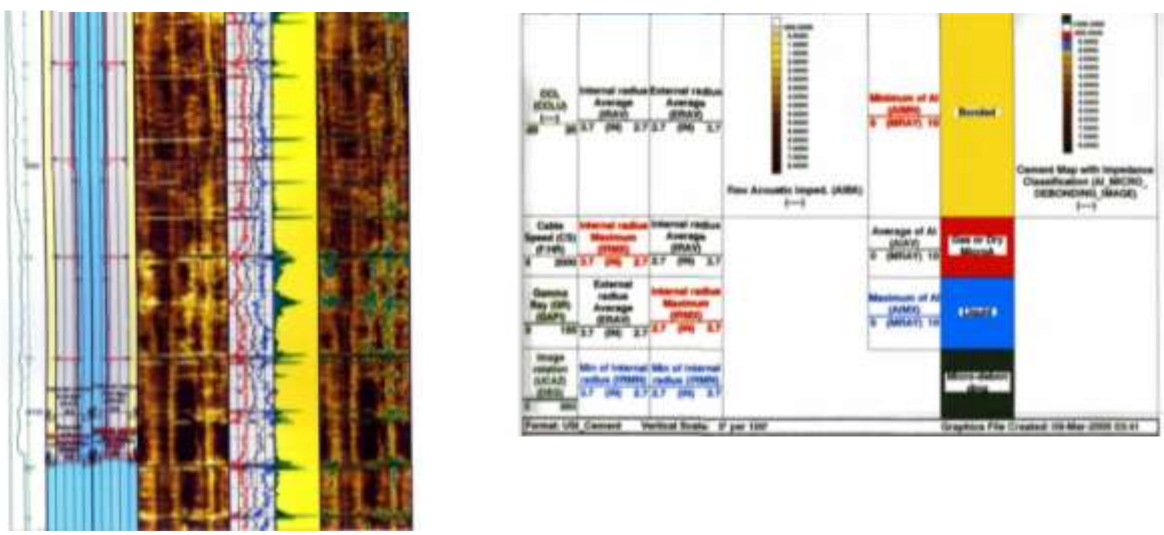


Table 3. Acoustic Properties of Materials (Smolen, 1996)

Material	Density (Kg/m³)	Acoustic Velocity (m/sec)	Acoustic Impedance (MRayl)
Air	1.3 – 130	330	0.0004-0.04
Water	1000	1500	1.5
Drilling Fluids	1000-2000	1300-1800	1.5-3.0
Cement Slurries	1000-2000	1800-1500	1.8-3.0
Cement (Litefil)	1400	2200-2600	3.1-3.6
Cement (Class G)	1900	2700-3700	5.0-7.0
Limestone	2700	5500	17
Steel	7800	5900	46

The **Segmented Bond Tool (SBT)** is a radial cement bond device, which measures the quality of cement effectiveness, both vertically and laterally around the circumference of the casing. The SBT is designed to quantitatively measure six segments, 60^0 each around the pipe periphery and employs an array of high-frequency steered transducers which are mounted on six pads. Each of six motorized arms positions a transmitter and receiver against the casing wall. The SBT is usually run with a VDL (variable density log). A primary SBT presentation has (1) a correlation trace and (2) two attenuation traces that are an average of the 6 segmented measurements and a minimum attenuation trace representative of the 60^0 segment with the least attenuation. A separation of the two attenuation curves indicates a cement void on one side of the casing and a continuous wide separation over an extended depth interval infers the present of channeling within the cement sheath. An example Segmented Bond Tool (SBT) log run on an injection well is shown in Figure 20.

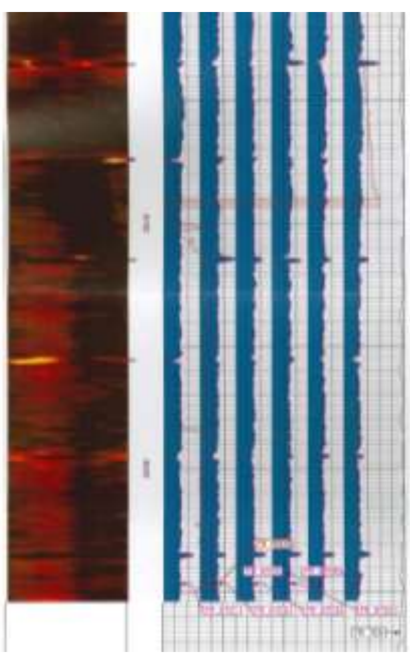


Figure 20. Example SBT Log

Factors that Affect Cement Log Quality

There are many factors that affect the response of sonic logging tools. These factors include: micro-annulus, logging tool centralization, fast formation arrivals, use of lightweight cements and cement setting time (Boyd et al, 2006).

<u>Micro-annulus.</u> A micro-annulus is defined as a very small (approximately 0.01 to 0.1 mm) annular gap between the casing and the cement sheath. A micro-annulus can result in a misinterpretation of the CBL/VDL. Micro-annuli are caused by temperature, mud-cake deposits, pipe coatings and constraining forces. A common procedure is to pressure up the casing to approximately 1,000 to 1,500 psi and close the gap (if the cement job was good). Micro-annuli affect ultrasonic tools much less than the CBL/VDL and SBT (pads) in the presence of liquid in the gap with the opposite effect in the presence of gas.

<u>Eccentralization.</u> This may be an issue particularly in deviated and horizontal wells with the absence of cement on the low side and the distance between the casing and formation face is small.

Figure 21. MIT Tool

<u>Logging Tool Centralization.</u> It is mandatory that the USIT and the CBL/VDL tools are well centralized. The SBT pads with their articulated arms are relatively unaffected by the centralization issue, although the CBL/VDL part of the tools is affected. Tool centralization can be checked in the log presentation.

<u>Fast Formations.</u> Formations with very high velocity and short transit time are called "fast formations". Acoustic signals from anhydrites, low porosity limestone and dolomites often reach the receiver ahead of the pipe signal. Fast formations affect the CBL/VDLs and SBT logs but do not affect USIT interpretation.

<u>Lightweight Cement.</u> Cement evaluation relies on the contrast in the acoustic properties of the cement and liquid. The acoustic properties of lightweight cement (commonly used in areas of weak formation) are close to those of cement slurry making it difficult to distinguish between the two.

<u>Cement Setting Time.</u> This is an important consideration in CBL interpretation. If the bond log is run before the cement is fully set, a misinterpretation indicating poor bonding may result in an unnecessary squeeze operation. The hardening time of cement slurries depend on their type and formulation, the down-hole temperature profile and pressure conditions, and extent of drilling mud contamination. The U.S.EPA recommends a 72 hour waiting on cement (WOC) prior to logging UIC regulated wells, while the American Petroleum Institute (API) and the Alberta Energy and Utilities Board suggest a 48 hour WOC time (for oil and gas related production and injection wells). The ultrasonic cement analyzer (UCA) can be utilized to determine when to log and has shortened the WOC time.

To declare zonal annular isolation between two points behind casing, a minimum length of continuous good quality cement should exist. A recommendation of 33 feet of continuous good cement for the 7 inch casing and for 45 feet for 9 5/8 inch casing has been reported in a EPA publication, while oil industry service company recommendations for continuous good quality cement are 10 to 11 feet for 7 inch casing and 15 feet for 9 5/8 inch casing, to assure zonal isolation (Boyd et al, 2006).

Finally, it should be noted that even if cement quality logs indicate good bonding and zonal isolation, there may be annular communication resulting from reactions between the rock, cement and formation fluids in production wells.

Zone Isolation/Pressure Testing

Placement of the cement completely around the casing and at the proper height above the bottom of the drilled hole (cement top) is one of the primary factors in achieving successful zone isolation and integrity. It is good practice to pressure test the shoe after drilling out the cement shoe on the surface and intermediate/longstring casing strings and confirm zonal isolation at the shoe. This involves pressuring up inside the casing until the pressure at the shoe exceeds the maximum hydrostatic pressure expected at that point during subsequent drilling operations. Failure of cement around the shoe is usually due to contamination, either from the original drilling mud or from the displacement fluid and usually results from poor cementing techniques rather than poor quality cements since hard-set neat cement has sufficient strength to withstand pressure tests.

Multi-finger Caliper Surveys

Multi-finger caliper logs (multi-finger imaging tools - MIT) are used to detect very small changes to the internal surface condition of tubing from the impacts of corrosion and/or mechanical damage. The tool may be run through tubing to log casing deeper in the well. They are available in 24, 40 and 60 fingers or arms (tool diameters of 1.6875, 2.75 and up to 4.4 inches respectively) to suit varying casing/tubing sizes. The number of fingers increases with the diameter of the tool and when the tool is run in the hole, the fingers are closed to prevent damage. Tool deployment can be via slick-line, e-line, coiled tubing or down-hole tractors. The magnetic thickness tool (MTT) uses 12 miniature magnetic sensors, to investigate variations of metal thickness within down-hole tubular. Data from the multi-finger imaging and magnetic thickness tool can be combined to assess both the internal and external condition of the tubular including maximum cross-sectional wall loss, maximum penetration (pitting etc.) and reduction in wall thickness. A representative MIT and MTT tool is shown in Figure 21 and Figure 22, and an example multi-finger caliper survey run on an injection well is shown in Figure 23**.**

Figure 22. Magnetic Thickness Tool (MTT)

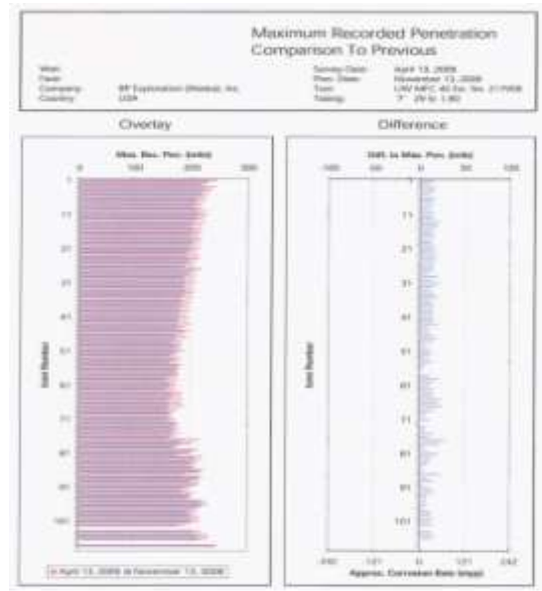


Figure 23. Example of Multi-Finger Caliper Survey

Oxygen Activation/Water Flow Log/Hydrolog

Oxygen Activation logs also referred to as a Water Flow Logs (WFL) or Hydrologs are used to detect water flow or channels behind casing in injection or production wells. The principle of water detection using Oxygen Activation can be explained as follows – when the neutron burst is generated by the tool, the oxygen associated with the up-flowing water is activated to an unstable nitrogen isotope having a half-life of 7.35 seconds (oxygen activation effect).When the nitrogen isotope returns to its native oxygen, gamma rays are emitted which may be detected by the near or far background count measurement. The times under consideration are long after the inelastic or capture gamma rays have ceased.

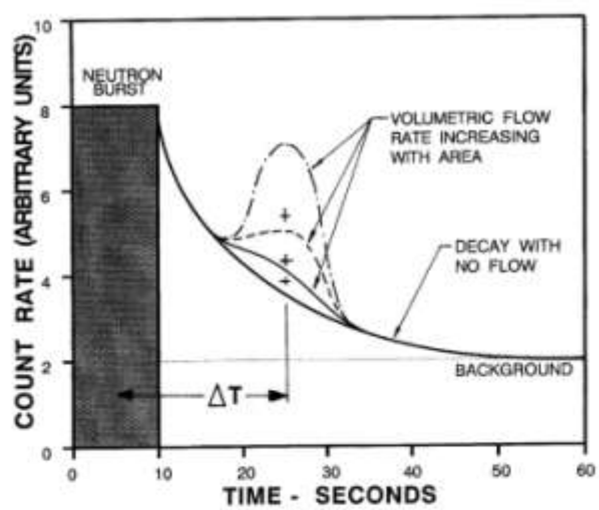


Figure 24. WFL Measurement Technique

The WFL is a dual burst TDT (thermal decay time) with a modified pulse sequence. Unlike a conventional TDT log, the OA/WFL needs to be run centralized. The operation of a WFL is shown in Figure 24. The neutron generator is turned on for either 2 or 10 seconds, then turned off. If no water flow is present, then the count rate decays as shown, reaching background after about one minute. If water flow is present, then the count rate decays as before, until the activated water moves adjacent to the detector. When that occurs, excess counts are observed. After the cloud of activated water passes, the counts return to the background decay curve. The data are recorded on three detectors, typically the near (N), far (F), and gamma ray (GR). Only one will be typically optimized to provide good data. While each burst and decay sequence takes about 1 minute, the data collected may be highly statistical, and therefore the burst and decay sequence will typically be repeated up to about 10 to 15 times. Figure 25 shows a WFL run on a well in Alaska.

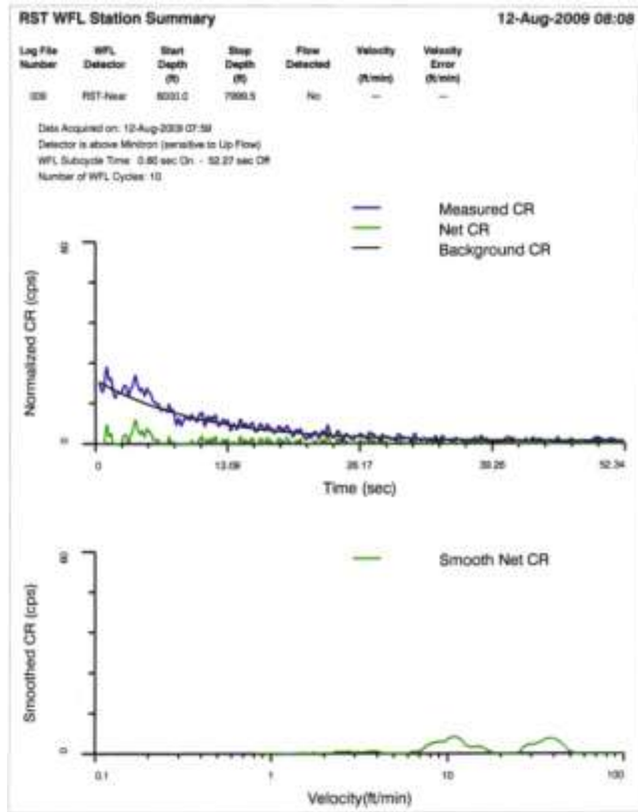


Figure 25. Example of WFL Log

Borax PNL Logs

Channel detection using temperature or noise logs is often ambiguous. In certain areas, radioactive (RA) tracers cannot be used either due to safety, environmental, or political reasons. As a result, a technique based on the higher capture cross section of boron has been developed in Alaska to locate channels behind pipe. The borax compound generally used is sodium tetra-borate penta-hydrate ($Na_2B_4O_7$), due to its high capture cross section, low cost, and ready availability. The mix rate used in Alaska is 7 pounds/barrel of warm seawater.
The Borax PNL technique involves comparing pulsed neutron log (PNL) passes run before and after pumping a solution of borax dissolved in warm water as a tracer. A PNL indicates a significant Sigma value when boron is present, so an overlay of log passes quickly indicates those areas within and adjacent to the wellbore where boron accumulates due to injection of the tracer. An illustrative example of a Borax-PNL log run in Alaska is shown in Figure 26.

Ultrasonic Leak Detection Logs

A new tool that has demonstrated success in the North Slope of Alaska in detecting leaks as small as 0.0024 gallons per minute (gpm) is the ultrasonic leak detection logging tool run on wire-line or on slick-line in memory mode (Julian et al, 2007). The tool is particularly useful where rig workovers are expensive as in remote locations, offshore or in Arctic regions. It can detect leaks through multiple strings because ultrasound is not significantly attenuated by gas, liquid, or steel. Other advantages include: (1) it can be run in high pressure wells in which it is difficult to maintain a pressure seal for the wireline, and (2) in memory mode a tandem multi-finger caliper and a leak detection log can be obtained in one run. Many injection wells were previously producers and therefore have gas-lift mandrels. MI gas consists of 35% methane, 20% each of ethane, propane, and carbon dioxide. MI gas is an excellent solvent and easily dissolves grease seals, o-rings, and elastomers. A schematic of the ultrasonic tool is shown in Figure 27.

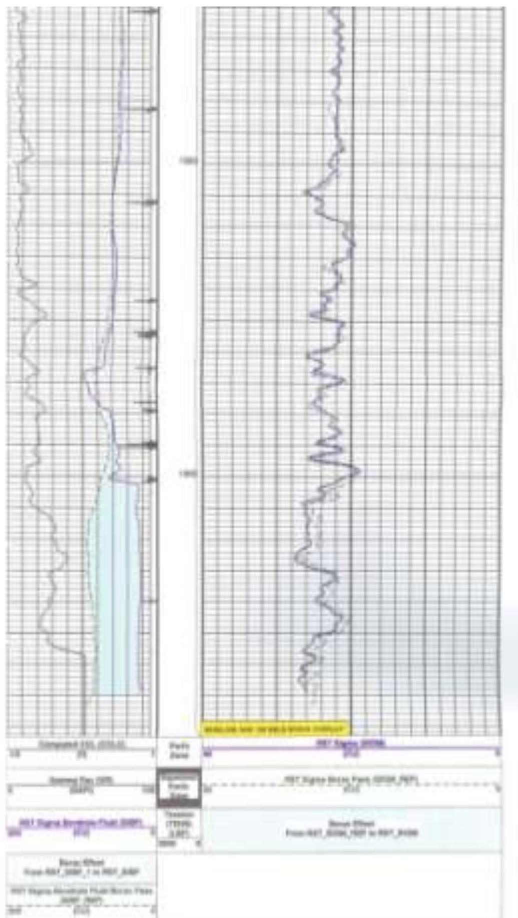


Figure 26. Example Borax-PNL Log

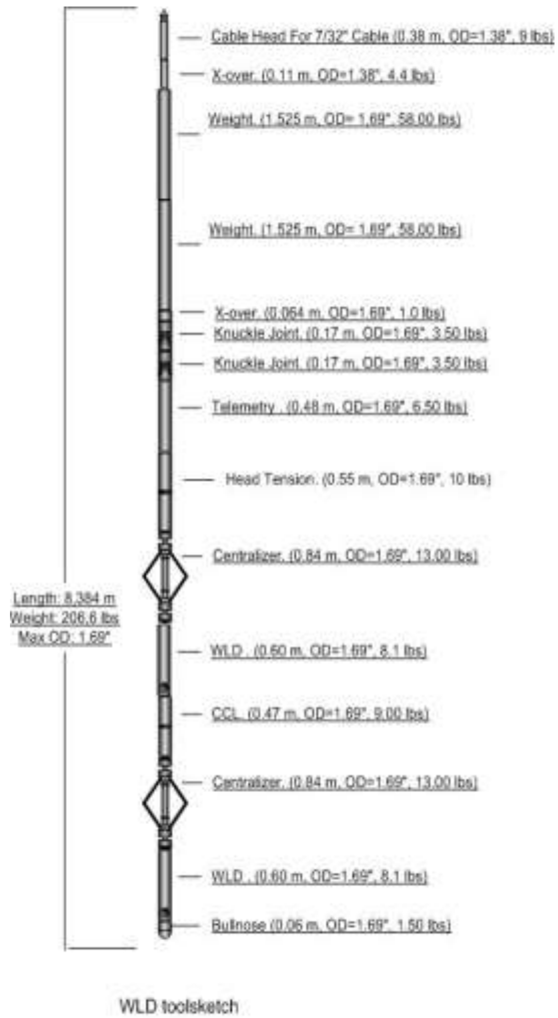


Figure 27. Ultrasonic Leak Detection Tool

Tree and Wellhead Integrity

The wellhead and tree are typically suitably engineered to withstand the normal operating pressures. For normal operations and during hydraulic fracturing operations, if the annulus between the production casing and the intermediate casing has not been cemented to the surface, the pressure in the annular space should be monitored and controlled. The intermediate casing annulus should be equipped with an appropriately sized and tested relief valve. The relief valve should be set so that the pressure exerted on the casing does not exceed the working pressure rating of the casing. Pressure exerted on equipment should not exceed the working pressure rating of the weakest component.

Wellhead seal tests need to be conducted to test the integrity of the sealing elements (including valve gates and seats) and confirm their ability to seal against well pressure. If abnormal annular pressures are noted, a re-pressure test of the wellhead system can help determine whether it is a surface wellhead leak as opposed to a subsurface leak.

Horizontal Wells

In general, horizontal wells have had great success in high-permeability reservoir and unconventional formations such as coal, chalk and shale. With the advancement of drilling and completion technologies, horizontal wells have become the industry standard for unconventional and tight formation gas reservoirs. Horizontal wells are commonly two to four times more expensive to drill and complete than offset vertical wells, yet are theoretically capable of up to three to five times the production. Environmental advantages with horizontal wells include a smaller drilling footprint with a reduction of well locations.

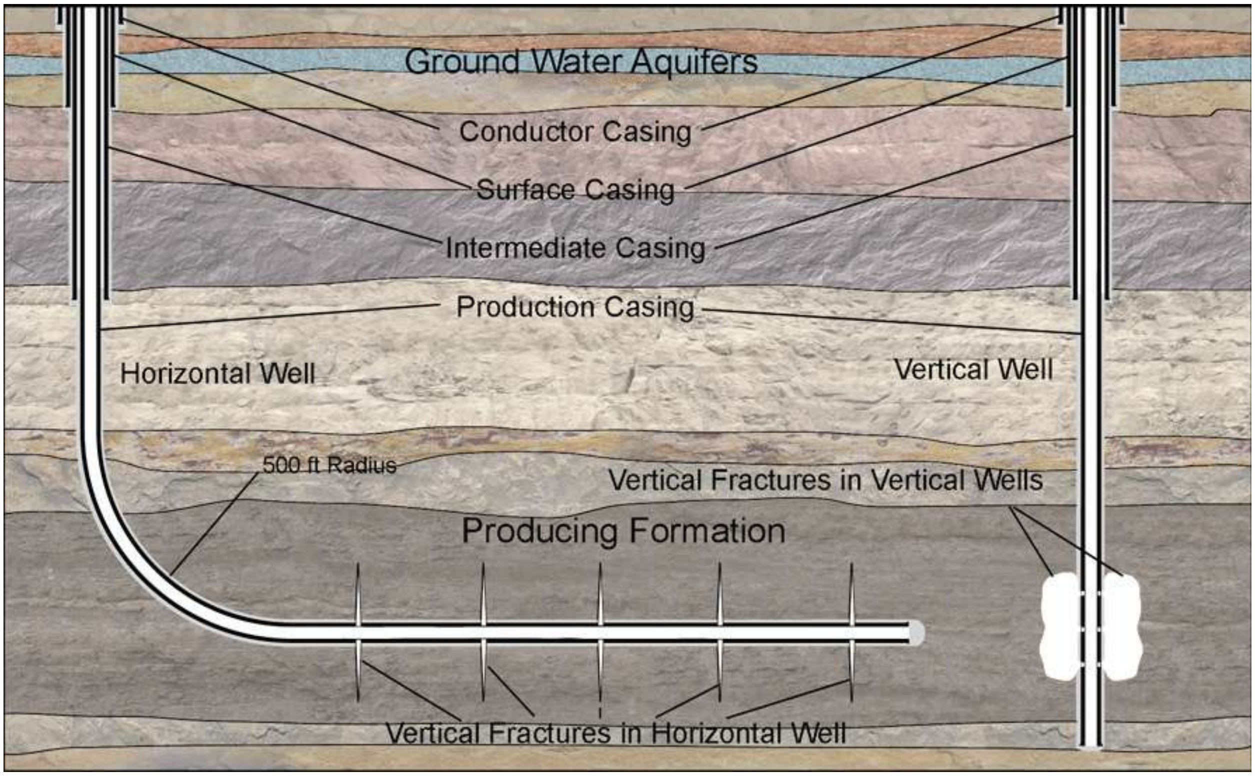
Horizontal wells are typically drilled vertically to a “kick-off” point where the drill bit is gradually turned from vertical to horizontal (see Figure 28). Horizontal wells use basically the same or similar equipment as vertical wells such as safety valves, packers and seal assemblies, flow control accessories, permanent down-hole gauges, artificial lift accessories etc. Tool manipulation is hydraulic or with reciprocation, while rotationally actuated tools should be used with caution. Intervention into the horizontal section requires coiled tubing, down-hole tractors or workstring.

Horizontal wells are completed with various degrees of annular isolation. Un-cemented or open- hole completions offer open access to fracture swarms, which may be plugged off or inaccessible if annulus is cemented. With open- hole or barefoot completions the most productive part of the interval has a better chance to be stimulated. Also, un-cemented completions avoid perforation-related stress cages that can result in a large extraneous source of treatment pressure drop. In this alternative, the producing portion of the well is the horizontal portion of the hole and it is entirely in the producing formation. In some instances, a short section of steel casing that runs up into the production casing, but not back to the surface, is installed. Alternatively, a slotted or pre-perforated steel casing may be installed in the open-hole section. These alternatives are generally called a “production liner” and are typically not cemented in place. In the case of an open-hole completion, the tail cement should extend above the top of the confining zone (the formation that limits the vertical growth of the fracture).

Cased and cemented horizontal completions offer greater control over fracture treatment placement and can be appropriate when dealing with relatively uniform rock. Where cemented completions are warranted, sand jet perforating is preferred as it removes formation material and thus avoids the stress cage related pressure drop.

Discontinuous multi-layer intervals such as stacked, fluvial-dominated sandstones are best completed with vertical wells in multi-stage treatments.

Figure 28. Example of a Horizontal and Vertical Well (API, 2009)



Hydraulic Fracturing

Hydraulic fracturing (HF) has been employed in the oil and gas industry since 1947 and allows the production of hydrocarbons from low permeability (tight) reservoirs economically. The process of hydraulic fracturing increases the exposed area of the producing formation, creating a high conductivity path that extends from the wellbore through a targeted hydrocarbon bearing formation for a significant distance, so that hydrocarbons and other fluids can flow more easily from the formation rock, into the fracture, and ultimately into the wellbore.

During HF, fluid is pumped into the production casing, through the perforations (or open hole), and into the targeted formation at high enough pressures to cause the rock to fracture; this is known as “breaking down” the formation. As high pressure fluid injection continues, the initiated fracture can continue to grow or propagate. The rate at which the fluid is pumped must be fast enough that the pressure necessary to propagate the fracture is maintained. This pressure is known as the propagation or extension pressure. As the fracture continues to propagate, a proppant, such as sand, is added to the fluid. The proppant allows the fracture to remain open when pumping is stopped (and the excess pressure is removed), allowing fluids to flow more readily through this higher permeability fracture. During the HF process, some of the fracturing fluid may leave the fracture and enter the untreated formation resulting in fluid leak-off. The fluid flows into the micropores or pore spaces of the formation or may intersect existing natural fractures in the formation.

In order to carry out the HF process, a fluid must be pumped into the well's production casing at high pressure. The production casing must be properly designed, installed and cemented so that it is capable of withstanding the pressure that it will be subjected to during the HF process. In some cases, a high pressure "frac string" may be used to pump the fluids, thereby not exposing the production casing to the high treatment pressures. Once the HF process is completed, the frac string is removed.

In the field, the HF process is called the "treatment" or "job" and consists of three stages:

- Pad – The pad is the first stage of the job where the fracture is initiated and is propagated in the formation. Another purpose of pad is to provide enough fluid volume within the fracture to compensate for fluid leak-off into the formation.
- Proppant Stages – Here proppants of varying concentrations are pumped. Most common proppant is ordinary sand sieved to a particular size. Other proppants include sintered bauxite and ceramic proppant.
- Displacement – Here the previous sand laden stage is displaced to a depth just above the perforations. This is done so that the proppant ends up within the fracture and not within the pipe. Sometimes called the flush, the displacement stage is where the last fluid is pumped into the well. The flush fluid could be plain water or the same fluid that was pumped earlier.

In wells with long producing intervals (both vertical and horizontal), the HF process can be done in a multi-stage process allowing for better control and monitoring of the HF process.

Post-Hydraulic Fracturing Monitoring

Prior to the HF treatment, the proppant, usually sand, may be "tagged" with a tracer. After the proppant has been pumped into the formation, a cased-hole log, capable of detecting the tracer, is run to confirm the proper placement of the proppant. A temperature survey in conjunction with the tracer log can also be run. Since the HF fluid is typically at ambient temperature at the surface and the formation temperature at the target depth is much higher, the formation is cooled considerably during the HF treatment showing which perforations accepted the fracturing fluid. The use of these techniques is declining with the advent of sophisticated computer modeling techniques for mapping fracture growth and geometry.

Refracturing

Refracturing of oil and gas wells (also known as fracture re-stimulations) are becoming increasing popular as this technique, under certain conditions, can restore or increase well productivity and ultimate hydrocarbon recovery. Re-stimulations can by-pass near well-bore damage and generate higher conductivity propped fractures resulting in more lateral extension and deeper penetration of the fractures, with ultimate higher hydrocarbon recovery.

More than 30% of fracturing treatments are performed in older wells, therefore, mechanical integrity of the tubular becomes critical in candidate selection for HF treatments. Surface casing vent flows must be checked and any indication of gas migration to the surface will result in the elimination in the well as a candidate.

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