MAINTAINING AND REPAIRING CASING INTEGRITY

BOTTOM LINE

The oil and gas reservoirs of Kansas are very mature and subject to both chemical and electrolytic corrosion, ranging from moderate to severe. Casing leaks in production wells can cause increased water production and reduced oil and gas production. Leaks in injection and disposal wells can endanger fresh groundwater and must be reported to the Kansas Corporation Commission and subsequently repaired or plugged. Detection and repair of leaking casing can be difficult and expensive. It is much more cost effective to initiate steps to prevent the corrosion.

PROBLEM ADDRESSED

The problem addressed is three-fold: How do you prevent corrosion from compromising the casing integrity? If it is compromised, how does the operator identify the nature and location of leak? And once located, what options are available to repair the damage in the most cost effective manner?

KEY WORDS:

Casing Patch
Cathodic Protection
Cement Squeeze
Chemical Permeability Modifier
Class II Wells
Corrosion Inhibitor
Magnetic Flux Survey
Mechanical Integrity
Wellbore Imaging

TECHNOLOGY OVERVIEW

Detecting, Locating and Characterizing Casing Damage and Leaks

Detecting casing corrosion defects and leaks and external cement channels can be accomplished a number of ways—observation in changes in production, injection or pressure; mechanically with packers and removable bridge plugs; visually; and with an assortment of wireline tools. Several speakers addressed the latest technology for identifying the nature and location of casing problems.

Based on a half day workshop sponsored by PTTC's North Midcontinent Region and SPE Wichita Section in Wichita, Kansas on April 11, 2006.

SPEAKERS:

Underground Injection Control,
Alan Snider, Kansas Corporation Commission

Tubing and Casing Evaluation Utilizing Magnetic Flux Leakage Technology,
Don Vogtsberger, Baker-Atlas

Downhole Video Pipe Inspection,
Ed Barret, Eagle Vision Video

Casing Inspection on Wireline: UltraSonic Imager and Multifinger Imager Tools,
Stefanie Merkel, Schlumberger

Cement Squeezing Casing Leaks,
Rodney Reynolds, PTTC/TORP

HOMCO Internal Steel Casing Patch,
Wes Randall, Weatherford

Cathodic Protection: Prevention That Pays,
John Francis, Corrosion DC

Corrosion Control,
Sam Toscano, Baker Petrolite

Underground Injection Control

The Kansas Corporation Commission (KCC) has jurisdiction over the mechanical integrity (MI) of Class II wells, injection wells for waterflood or enhanced oil recovery and brine disposal wells. MI addresses internal leaks in the casing, tubing or packer and external leaks allowing fluid movement behind the casing into an underground source of drinking water. Wells are tested every five years and the operator files an annual monitoring report. If a leak is detected the well must be shut in until repaired and tested or plugged. MI test methods can be used individually, or in combination and include:

- Standard Annulus Pressure Test
- Standard Annulus Monitoring Test
- Fluid Depression Test
- Dually Completed Monitoring Test
- Simultaneous Injection
- Temperature Log
- Radioactive Tracer Survey
- Noise Log
- Oxygen Activation

The operator must file a plan to repair the well that is approved by the KCC. Repair methods include cement squeeze, drill out and repair, mechanical isolation with dual packers or bridge plugs, or chemical sealants of polymers or other mixtures. When completed, the well must be tested and demonstrate that it can hold pressure for thirty minutes. The KCC oversees 2,500 to 3,500 tests annually with a 7% failure rate, and actually witness 67 to 100% of the tests, depending on the region.

Tubing and Casing Evaluation Utilizing Magnetic Flux Leakage Technology

The use of magnetic flux leakage (MFL) technology to determine the location, extent and severity of corrosion and other metal loss defects in carbon steel tubulars through the use of permanent magnets is an established technology. It began to be used extensively in pipelines in particular in the 1960s and 1970s. The tools produce high levels of magnetic flux within the tubing or casing wall. Defects such as internal or external corrosion pitting cause flux perturbations that are detected by a circumferential array of inductive coil sensors. The tools also employ a circumferential array of discriminator sensors that respond to flux anomalies occurring only on the inner surface, so the combination can differentiate between internal and external features. The response can tell the operator of corrosion inside, outside or all the way through the casing and the degree of severity and can be used in tubing as small as 2 7/8 inch through pipe as large as 20 inches.

The advantages of this survey are:

- Detects internal and external defects
- Fast—7,200 ft/hr
- Repeatable—can be used to monitor year to year changes
- Safe—no damage to tubulars or lining
- Robust—is not distorted by scale or paraffin, works in any fluid or gas
- Improving Signal/Noise with increasing corrosion detects degree of damage
- Locates collars and other downhole equipment for inventory of wells with poor records

Disadvantages include:

- Indirect Measurement—you can't actually view the damage
- Poor sensitivity to axially-oriented defects and mechanical deformation
- No interpretation is possible in the collars

Downhole Video Pipe Inspection

A relatively new technology for the location and identification of corrosion and leaks in tubing and casing is the downhole video pipe inspection. Unlike earlier versions in the 1970s, today's cameras are color, smaller, higher resolution and capable of looking downhole or circumferentially. The cameras have very precise depth measurement and are fairly compact at 2 3/8-inch diameter and three feet length. The video is monitored in-cab with digital depth read-out, checked against the manual counter, connected with an optic fiber cable and recorded digitally on DVD.

The cameras require that the hole be well cleaned and scraped before running (primarily to avoid sticking). As expected in an optical view, it cannot be used in fluids where the light is ineffective, such as oil or water with a lot of suspended fines. By applying surfactants to the lenses however, it can be lowered through oil to view the well in water below. Besides direct observation of corrosion and holes, it can be used to observe scale (different kinds show up as different colors) and junk or obstructions in the wellbore. It has multiple uses in oil, gas and storage wells, water wells of various types, and cavern inspections. Besides the limitations of the fluid in the well, it cannot detect corrosion on the outside of the casing or poor cement bonds.

Casing Inspection on Wireline: UltraSonic Imager and Multifinger Imager Tools

Two new wireline tools are available to survey wells for corrosion and leaks. The first, the Ultrasonic Imager, uses a single transducer mounted on an ultrasonic rotating sub on the bottom of the tool. The transmitter emits ultrasonic pulses and measures the received ultrasonic waveforms reflected from the internal and external casing interfaces. The rate of decay of the waveforms received indicates the quality of the cement bond at the cement/casing interface and the resonant frequency of the casing provides the casing wall thickness. Because it is mounted on a rotating sub, the entire circumference is scanned. The angular and vertical resolutions can detect channels as narrow as 1.2 inches. It is very versatile as it evaluates the cement integrity, corrosion damage—internal and external, and ovality. With this information the casing can be analyzed for collapse and burst pressure. The tool is 20 ft. long and runs in water- or oil-based mud and tolerates high pressures and temperatures.

The second tool is the Multifinger Imaging tool. It is a multifinger caliper tool that makes highly accurate radial measurements of the internal diameter of tubing and casing strings. It comes in three sizes for a range of diameters. It deploys an array of hard-surfaced fingers which accurately monitor the inner pipe walls. Eccentricity effects are minimized by equal azimuthal spacing of the fingers and a special processing algorithm. Applications include identification and quantification of corrosion damage, identification of scale, wax and solids accumulation, monitoring of anticorrosion systems, location of mechanical damage and determination of the absolute inside diameter.

Repairing Casing Leaks

Once a leak has been detected, the optimal repair solution must be determined. Repairs can be mechanical, with packers, bridge plugs or patches, or chemical, with cement or permeability modifying chemicals. Two methods were highlighted, the first the most established, the cement squeeze job, the second a relatively new technology, the casing patch.

Cement Squeezing Casing Leaks

Once the nature of the leak is detected by one of the methods described above, a solution for the economic repair must be determined. One of the most common tried and true methods is the cement squeeze job. Cement squeezing is basically a filtration process. The cement slurry is subject to differential pressure against a filter of permeable rock and begins to lose part of the mix water, leaving a cake of partially dehydrated cement particles. The rate of cake buildup is a function of formation permeability, differential pressure applied, time and the capacity of the slurry to lose fluid.

Low fluid loss slurries, when squeezed against low permeability formations, will dehydrate slowing making the operation excessively long. High fluid loss slurries will lose water to high permeability rocks too fast, bridging off channels that otherwise would have accepted the cement. With the ideal slurry, the rate of cake growth is controlled so that a uniform filter cake builds over all permeable surfaces. The dehydration of cement requires intermittent application of pressure, separated by a period of pressure leakoff caused by the loss of filtrate to the formation and is referred to as "hesitation squeezing." The initial pressure leakoff is usually fast, due to little or no filter cake, allowing short periods between pumping stages at the beginning of the job. As the filter cake builds up, the filtration periods become longer and the difference between initial and final pressures becomes smaller until the pressure leakoff becomes negligible. At the surface, indication of a complete fill-up is given by the lack of pressure leakoff at a pressure 300 to 500 psi higher than the final injection pressure. The pressure test generally lasts 10 to 15 minutes.

Squeezing techniques include low pressure and high pressure. Low pressure squeezing is conducted below frac pressure, is near wellbore and low volume. It is used in depleted formations to spot cement at the perforations to prevent fracturing due to hydrostatic pressure. High pressure squeezing breaks down the formation and fills fractures or microannuli. The location and orientation of the fracture cannot be controlled. If properly performed, it leaves cement close to the wellbore. The properties of the cement slurry must be tailored according to the characteristics of the formation to be squeezed off and the technique to be used. Important considerations include fluid-loss control, volume and thickening time. Compressive strength is not an issue. The slurry can be placed with or without (bradenhead) packers. Packers are used to isolate casing and wellhead from high pressure. A bradenhead squeeze is generally done at low pressure where there is no doubt that the casing can withstand the squeeze pressure.

HOMECO Internal Steel Casing Patch

The internal steel casing patch is a thin wall steel liner that is run in a corrugated configuration (before setting) with a fiberglass mat, covered with epoxy, on the outside. It can be used to seal leaks in tubing or casing including perforations, collar or thread leaks and splits as well as reinforcing worn or corroded intervals. It is run on drill pipe or tubing using a drilling or workover rig. It is set (expanded) using a hydraulic pulling tool and expanding assembly. The advantages include speed (trip time plus 45 - 60 minutes), minimum reduction of the inside diameter (an unexpanded patch can be run through an expanded patch), multiple patches can be set and it works where squeezes have failed. The chief disadvantage is price: to set a 20 ft. patch is $10,000, plus rig time, pump rental, travel and supervision. The standard patch is a low carbon steel with a temperature rating of 325 °F. A high temperature patch is available for temperatures up to 600 °F and a corrosion resistant patch is available for use with stainless casing.

The information required to begin a job includes casing size and weight, hole deviation, differential pressure requirements, well fluid, weight, and level (the process works in all fluids except diesel), depth and description of damage, downhole temperature and the height and pulling capacity of the rig. The patch comes in 20 ft sections and 10 foot multiples. A double rig can set up to a 60 foot section, which can be prepared in the shop; otherwise they can be welded on site. It is recommended that when the patch is used for patching perforations or splits that it cover the entire region plus six to eight feet overlap above and below to avoid casing damage. The wellbore must be scraped and milled if needed for clearance, then circulated to clean it out. No sand at or above the damage can be tolerated. The procedure for the process is to:

- Running in the hole opens the slide valve allowing the workstring to equalize
- Lowering the tool below the interval to be patched and then pulling up to the setting depth closing the slide valve
- Initial pump pressure is applied from the surface anchoring the tool
- Additional pressure strokes the setting tool pulling the cone and collet through the first five feet of the patch, anchoring it to the internal casing wall in radial compression
- The remaining unset portion of the patch is set hydraulically or by straight pull

Corrosion Protection

Cathodic Protection: Prevention That Pays

Electrolytic corrosion will occur when four elements are present: anode, that releases metal ions to the electrolyte and electrons to the circuit, cathode, where electrons released at the anode are consumed, electrical circuit, the pathway between the anode and the cathode, and electrolyte, a solution containing conductive ions, usually brine. All elements have an electomotive rating that causes dissimilar metal to become anodes or cathodes. Cathodic protection is defined as the control of electrolytic corrosion by the application of direct current in such a way that the structure (casing or pipeline) to be protected is made to act as the cathode of an electrolyte cell.

Because of ground and formation chemistry, the degree of electrolytic corrosion can very from moderate to extreme. The technology to mitigate this type of corrosion is very well established. The sacrificial anodes are placed in the ground near the well or structure to be protected. A positive DC voltage is applied at a voltage that causes the electrons to flow to and corrode the anode from the cathodic areas. Generally the voltage is applied by taking AC power off the grid and applying a rectifier to convert to DC. If AC is not available an alternator system or solar panels and batteries can be used to generate the DC.

Corrosion Control

There are a number of corrosive agents found in the oilfield, including CO_2, H_2S (which can be a byproduct of bacteria), O2 and bacteria. Typical CO_2 corrosion is round-bottomed and steep walled with sharp edges. The pits are generally interconnected in long lines. Characteristic H_2S pitting is random and scattered over the surface. Pit bases are rounded and the walls steep. Cracks may be present in the bottom of the larger pits. Corrosion attack from oxygen produces pitting which is broad-based and one pit tends to combine with other pits. As the oxygen concentration increases in combination with acid gases, the corrosion problems greatly increase. A concentration of less than 50 parts per billion is preferable. Microbial induced corrosion (MIC) results from bacterial activity. It typically appears as under deposit corrosion and standard corrosion inhibitors are ineffective. Factors involved in oilfield corrosion include pH, chloride concentration, temperature (doubles for every 10 °C increase), pressure, and velocity.

A number of inhibitor products are available, but must be matched with the chemicals present and the physical facilities to be protected. Considerations include type (water- or oil-soluble), compatibility with other fluids and inhibitors, flash and pour points, concentration, method of application and cost versus performance. They can be applied as a batch (usual), continuous (expensive), or squeeze (rare).

A good corrosion monitoring system is the second most important aspect of a good corrosion control program. It will help the operator achieve the optimal level of control and detect changes in the system. Methods of measuring corrosion include weight loss coupons, linear polarization resistance, electrical resistance, and iron counts, generally used in combination. Weight loss coupons are low cost and easy, but only measure at the coupon location. Linear polarization resistance is easy to install and interpret, but needs conductivity between electrodes (brine) and needs expensive equipment. Electrical resistance probe are also easy to install with semi-real time measurement, but can foul in sour environments. Iron measurements are easy to determine and measure all corrosion upstream of sample site, but it can't be used in sour systems and the operator needs to know the surface area of the steel to calculate the corrosion.

For information on PTTC's North Midcontinent Region and its activities contact:

Rodney R. Reynolds, Project Manager, Kansas University Energy Research Center
1930 Constant Ave., Lawrence, KS. 66047-3726
Phone: 785-864-7398, Fax: 785-864-7399, Email: rreynolds@ku.edu

CONNECTIONS:

Ed Barrett
Eagle Vision Video Well Inspection LLC
P.O. Box 441
Pratt, Kansas 67124-0441
Phone: 620-388-2375
Email: edb@eaglevisionwell.com

John Francis
Corrosion DC, Inc.
P.O. Box 1353
Great Bend, KS 67530
Phone: 620-786-9920

Stefanie Merkel
Schlumberger
1325 S. Dairy Ashford St.
Houston, TX 77077
Phone: 281-285-1310
Email: merkel1@houston.oilfield.slb.com

Wes Randall
Weatherford
3801 Magnolia
Pearland, TX 77581
Phone: 281-652-1396
Email: wes.randall@weatherford.com

Rodney Reynolds
PTTC/TORP
1930 Constant Avenue
Lawrence, Kansas 66047-3726
Phone: 785-864-7398
Email: Reynolds@ku.edu

Alan Snider
Kansas Corporation Commission
130 South Market
Wichita, KS 67202
Phone: 316-337-6200
Email: a.snider@kcc.state.ks.us

Sam Toscano
Baker Petrolite
1675 Broadway, Suite 1500
Denver, CO 80202
Phone: 303-573-2772
Email: sam.toscano@bakerpetrolite.com

Don Vogtsberger
Baker-Atlas
2397 Traversfield Dr.
Traverse City, MI 49686
Phone: 231-947-2810
Email: don.votgtsberger@bakeratlas.com

The not-for-profit Petroleum Technology Transfer Council is funded primarily by the US Department of Energy's Office of Fossil Energy, with additional funding from universities, state geological surveys, several state governments, and industry donations.

Petroleum Technology Transfer Council, 16010 Barkers Point Lane, Ste 220, Houston, TX 77079
toll-free 1-888-THE-PTTC; fax 281-921-1723; Email hq@pttc.org; web www.pttc.org