CATO-2 Deliverable WP3.4-D05
Progress report: Specifications and design criteria for innovative corrosion monitoring and (downhole) sensor systems

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1 Executive Summary

The objective of this sub-project is to establish specifications and design criteria for corrosion monitoring and corrosion sensor systems used in CO_2 storage wells; this includes sensitivity analysis and an evaluation of technological maturity.

In the Year 1 programme, we review the tools deployed for downhole integrity monitoring principally in oil and gas wells. This is because there is an established body of literature and field experience in the oilfield. The tools reviewed in this document are based on mechanical, sonic, electromagnetic, optical and electrochemical principles. Table 1 provides a summary.

Table 1

Measurement principles, applications and limitations of the tools described in the report

Measurement principle	*Tool/measurement*	*Applications*	*Limitations*
Mechanical	Mechanical multi-finger caliper measurements	Used extensively to measure internal corrosion of tubulars	Cannot detect very small holes (pinholes) in pipe.
	Cased hole dynamic tester	Used to take formation pressure and fluid samples in cased wells	Can only be run in casings larger than 5½"
(Ultra)sonic	Sonic cement bond logging	Used to measure 'average' cement bond quality outside pipe	Cannot detect cement defects such as channels
	Ultrasonic cement bond logging	Provide information on both the cement sheath and casing	Can only be run in casings larger than 5½"
	Ultrasonic corrosion logs	Provides high resolution azimuthal coverage of the pipe	Cannot be run in gas
	Permanent ultrasonic corrosion monitoring	Permanent corrosion monitoring of the pipe	No evidence of actual deployment
Electromagnetic	Electromagnetic corrosion measurement	Corrosion in pipes	Responds to 'metal'; therefore, cannot measure non-metallic accretions in pipe
Optical	Downhole cameras	Visual inspection of the wellbore	Can only be run in gas. Depends on downhole visibility
	Distributed temperature sensor	Measure temperature profile along the well	Measure subject to drift over time
Electrochemical	Corrosion protection evaluation tool	Evaluation of effect of cathodic protection	

Many of the tools are used for integrity survey and a few for permanent monitoring. The sensitivity of the sensors needs to be investigated. In Year 2, we shall focus on investigating electrochemical sensors for monitoring the corrosion of the casing in CO_2 storage wells.

Distribution List

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Document Change Record

(This section shows the historical versions, with a short description of the updates)

Version	Nr of pages	Short description of change	Pages
2010.08.31		Final deliverable	

Table of Content

2 Applicable/Reference documents and Abbreviations

2.1 Applicable Documents

(Applicable Documents, including their version, are documents that are the “legal” basis to the work performed)

	Title	Doc nr	Version date
AD-01	Beschikking (Subsidieverlening CATO-2 programma verplichtingnummer 1-6843	ET/ED/90780 40	2009.07.09
AD-02	Consortium Agreement	CATO-2-CA	2009.09.07
AD-03	Program Plan	CATO2-WP0.A-D.03	2009.09.29

2.2 Reference Documents

(Reference Documents are referred to in the document)

	Title	Doc nr	Version/issue	Date

2.3 Abbreviations

(This refers to abbreviations used in this document)

CBL	Cement bond log
CHDT	Cased hole dynamic tester
DTS	Distributed temperature sensor
EN	Electrochemical noise
ER	Electrical resistance
o.d.	Outside diameter
i.d.	Inner diameter
LPR	Linear polarization resistance
VDL	Variable display log

3 Corrosion sensor systems for downhole applications

3.1 Mechanical multi-finger caliper measurements

Multi-finger caliper tools use sprung “feeler” arms to measure the internal diameter (i.d.) of the casing or tubing into which the tool is run. Figure 1 shows a typical caliper tool.

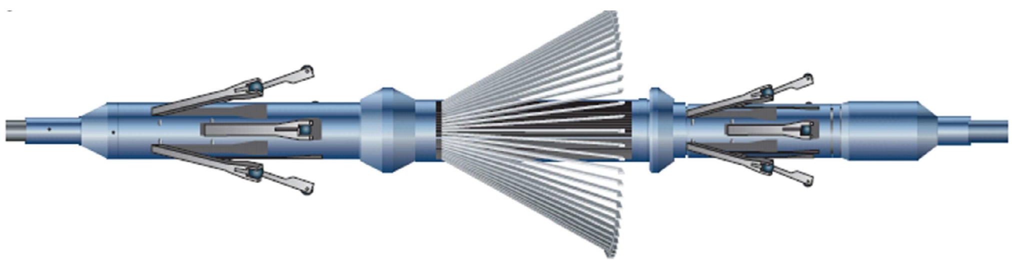


Figure 1: Mechanical caliper tools with feeler arms. (Source: Schlumberger)

The resolution of the tool depends on the number of “feeler” arms mounted on the tool: the higher the number of feelers the higher the azimuthally resolution. The tool shown in Figure 1 has sixty “feeler” arms. In addition to detecting corrosion of the pipe, the tool can be used to identify scale, wax and solid accumulations and locate mechanical damage, evaluate the progression of corrosion, and determine pipe i.d.

The i.d. readings from the tool can be used to present a 3D view of the pipe wall. This is especially useful for visualising the point of corrosion for well diagnostics (See Figure 2).

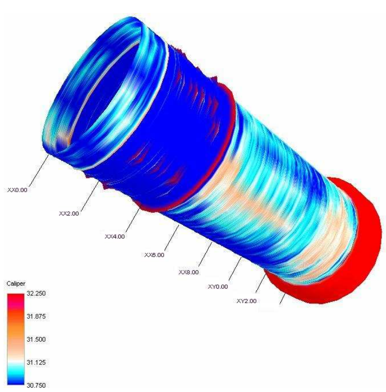


Figure 2: 3D picture of pipe based on data generated by the mechanical caliper shown in Figure 1 for diagnostics. (Source, Schlumberger).

Application

Oil companies routinely use caliper tools to estimate the degree of corrosion in hydrocarbon wells. The price of a caliper survey depends on many factors; these include the resolution of the tool, the location of the well (offshore versus onshore), the depth of the well and the post-acquisition processing.

Limitations

General	Tool cannot be installed in the well permanently; therefore, it is not suitable for permanent post-abandonment monitoring.
Can damage the pipe	Caliper tools actually 'scratch' the inside of the pipe; therefore, if run many times on a well, they may damage the pipe, creating hotspots from which local corrosion of the pipe can begin.
Provide information on innermost casing	Caliper tools measure only the i.d. of the pipe; they are not applicable where there is a need to measure the external corrosion of the pipe.
Cannot detect pinholes	Even though modern caliper logs are sensitive, they, by design, cannot detect extremely small holes (pinholes) in the pipe wall. Therefore, even if the caliper log suggests that the pipe is not corroded, there will still be uncertainty in the measurement of local corrosion.

3.2 Cased hole dynamic tester (CHDT)

The CHDT cased hole dynamics tester measures pressures at multiple points in the well and samples fluids behind a cased wellbore. It achieves this by:

- drilling through a cased borehole (casing and cement) and into the formation;
- performing multiple pressure measurements; and
- recovering the fluid samples.

Thereafter, the tool plugs the hole made in the casing. The tool is shown in Figure 3.

Figure 3: The cased hole dynamic tester (CHDT) (Source: Schlumberger)

	Applications
Cement samples	Take cement samples (after injection of CO_2) to estimate state of degradation of cement
Reservoir testing	Can be used to estimate the pressure and deliverability or injectivity of multi-layered reservoirs
Formation integrity	Used to conduct mini-fracs (and determine maximum allowable pressures) during CO_2 injection.
Annulus pressure investigation	In case of sustained casing pressure (SCP), tool can be used to ascertain reason for flow.
Test cement integrity	Tool can be used to test hydraulic isolation of zones of cement

	Limitations

Replugging?	Success rate of re-plugging is an issue; this is currently being improved
Tool size	It can only be run in casings larger than 5½" (tool o.d. 4¼")

Case study

In a North Sea water injection well, the operator wanted to increase the water injection rate (in order to increase hydrocarbon production [1]). However, there was poor cement outside the casing (refer to Figure 4). Therefore, there was uncertainty on whether increased injection would fracture the overlying high permeability formation.

Using the tool, the operator ascertained that there was indeed hydraulic communication behind the casing: the planned increase in injection pressure would be transmitted to the high permeability formation. Therefore, using the tool, a maximum 'safe' injection pressure was estimated and it was decided not to increase injection rate.

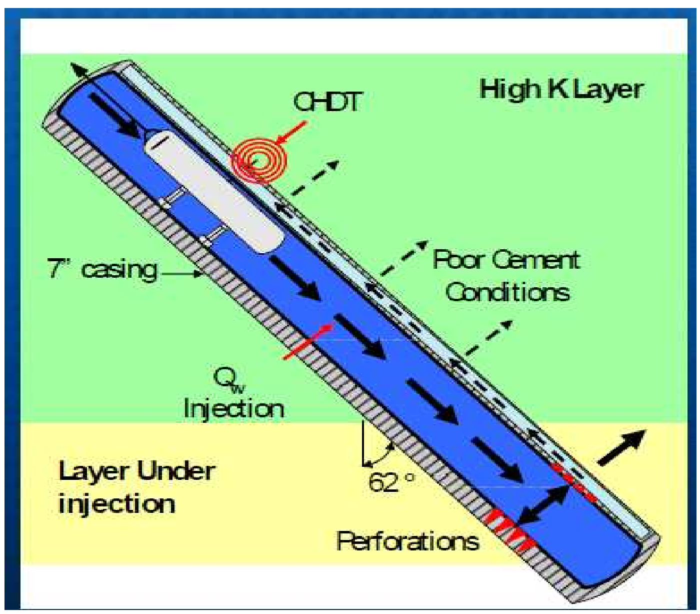


Figure 4 Application of the cased hole dynamic tester (CHDT). (Source: [1])

3.3 Single-point pressure and temperature

Downhole permanent pressure and temperature sensors are widely used in the oil & gas industry and in the underground gas storage industry; they are very mature and cost-effective technologies. In CO_2 storage, pressure and temperature sensors are crucial to the operational, reservoir and well integrity monitoring.

Many different types of pressure gauges have been developed over the years. For downhole pressure measurements, these include helical bourdon tube gauges, strain gauges, quartz crystal gauges and surface readout gauges.

For most CO_2 injection applications, digital quartz crystal gauges will be applicable (picture on the right). These gauges work on the principle that the resonant frequency of the crystal changes with applied stress (pressure) and temperature.

In the injection well, the bottom hole and the wellhead pressures and temperature are input to the control and optimization of the injection rate. Anomalies in their evolution will be early signs of a loss of integrity in the wellbore. Unexpected changes in temperature or pressure may be the sign of a fracturing cap rock, of CO_2 leaking through a shortcut, changing phase, reacting with cement.

Applications

Nowadays, pressure-temperature gauges are accurate and can be run across a wide range of pressure and temperature: up to 1,700bar, 250ºC. Applications include:

- local measurement of pressure for dynamic model calibration;
- monitoring loss of reservoir integrity, detecting hydraulic conductivity; and
- detection of CO_2 breakthrough.

3.4 Distributed temperature sensor

Distributed temperature sensors (DTS) use optical fibre made from doped quartz glass to provide a continuous temperature profile along the length of the wellbore. The method works on the principle that temperature changes the local light transmission characteristics of the glass fibre; temperature induces lattice oscillations within the solid. When light falls onto these oscillating molecules, an interaction occurs between the light particles (photons) and the electrons of the molecule.

Light scattering (Raman scattering) occurs in the optical fibre. Unlike incident light, this scattered light undergoes a spectral shift by an amount equivalent to the resonance frequency of the lattice oscillation. The light scattered back from the fibre optic therefore contains three different spectral shares, which are then used to compute the local temperature

Applications and limitation

CO_2 leakage in the cement or into the wellbore can induce local thermal effects, a local anomaly in the temperature distribution [2]. Comparing the continuous profiles over time allows identification of flow behind the casing and pin hole leaks through the tubing (due to the Joule-Thompson cooling effect).

While providing a profile along the length of the system, it is less accurate and more subject to data drift single point temperature measurement.

Case study [2]

In the CO2SINK project in Ketzin, CO_2 is injected into a saline aquifer. All the wells (injection and monitoring wells) are monitored using a DTS system (in addition, there is a pressure sensor in the injection well). Refer to Figure 5.

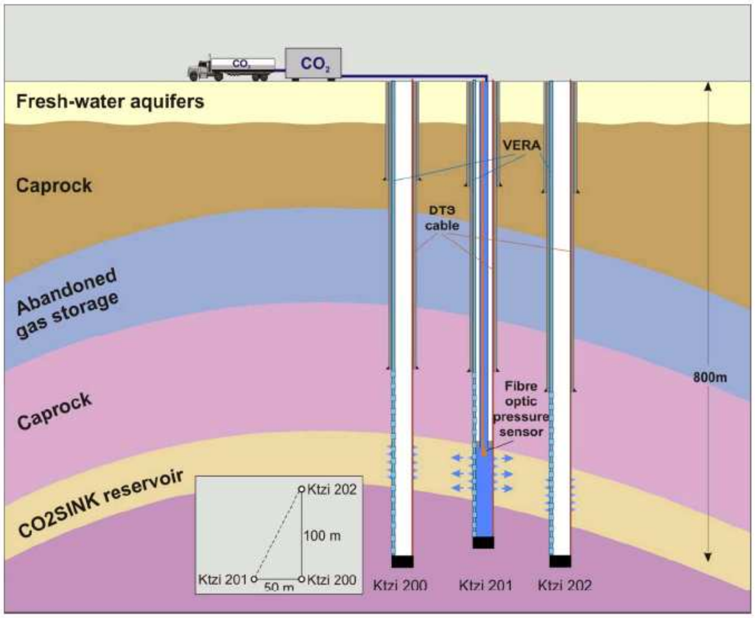


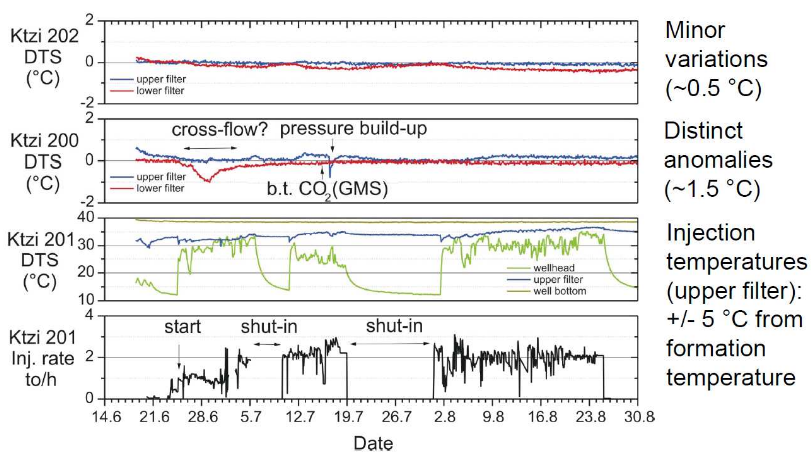
Figure 5 Overview CO_2 injection in Ketzin (from Jan Henninges, 2010).

The DTS measurements in all three wells showed the following (see Figure 6, panel a.):

- **Monitoring well Ktzi-202**. Minor variation in the temperature profile (consistent with data drift);
- **Monitoring well Ktzi-200.** distinct anomalies in the trend indicating movement of fluids in the wellbore;
- **Injection well Ktzi-201**. Variation of wellhead temperature with injection but smaller variation of bottomhole temperature

Closer inspection of the data in well Ktzi-200 confirmed that there was indeed cross flow (see panel b).

Panel a



Panel b

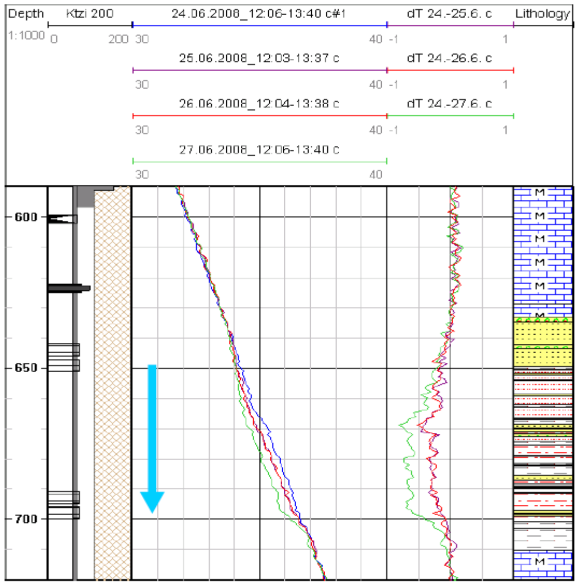


Figure 6: DTS measurements in CO2SINK project, Ketzin, show downward cross flow in monitoring well before CO_2 breakthrough (from Jan Henninges, 2010).

3.5 Sonic cement bond logging

Acoustic cement bond logging is a mature technology that is used to assess the quality of the cement bond and, thereby, used to deduce the likelihood of hydraulic isolation between formations penetrated by the well. Traditionally, the sonic cement bond log (CBL) is displayed with another log called the variable density log (VDL) [3].

The CBL and VDL measurements are made using a sonic tool, which omits an omni-directional acoustic pulse within the well fluid at a frequency range 20-27 kHz. These pulses travel as waves through casing, cement and formation along the axial direction of the tool and are eventually refracted back into the wellbore fluid and recorded by the receivers. Therefore, only a circumferential average of the cement bond is analysed. Figure 7 illustrates the principle of the measurement.

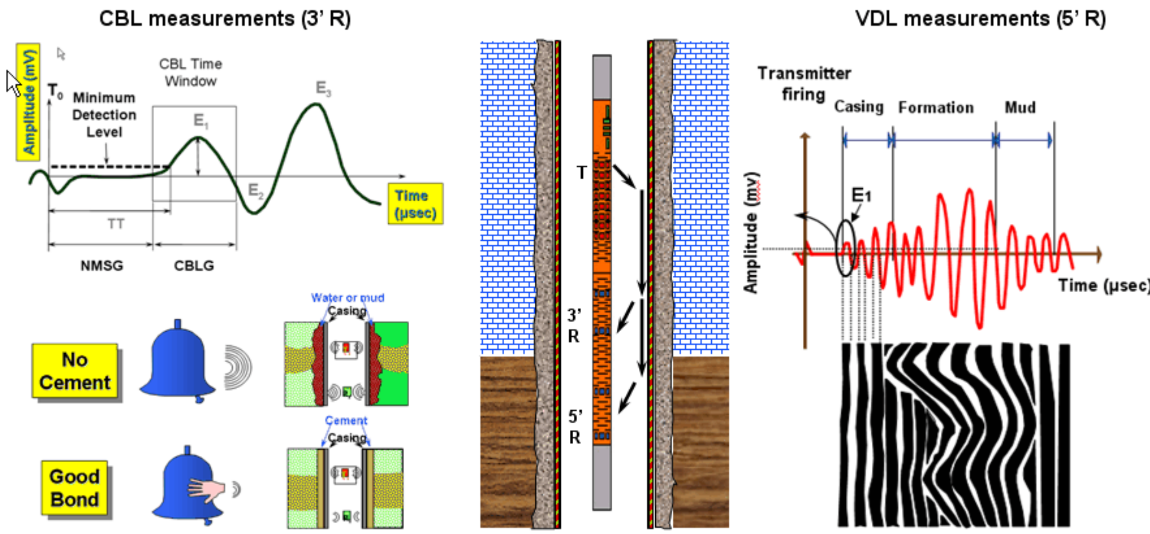


Figure 7: Principle of the sonic cement bond log (CBL) and the variable display log (VDL). (Source: [3-4]

Application and limitations

The CBL/VDL is backed by many years of experience in the oil industry. Furthermore it is relatively cheap to run and is applicable to wide range of casing sizes (even for 3½" tubing). However, it has some drawbacks. These are outlined below.

1.	**Sensitive to eccentering**	The tool must be properly centralised; eccentering causes an imbalanced sound path that makes interpretation very difficult; this is likely to be a problem in larger casings.
2.	**Affected by microannulus**	A microannulus is a very small annular gap (less than 0.5 mm thick) between the casing and cement. The presence of a microannulus reduces or eliminates the ability of the cement to support the pipe in shear, and the acoustic signal is free to travel through the pipe with little loss of energy to the surroundings[4]. The microannulus may not affect the integrity of the well but may give the same CBL response as poor cement, even though the annulus may be full of good cement during or after cement curing
3.	**Cannot detect channels**	Cement channeling is a condition, in which cement is present, but not does completely surround or bond to the casing circumference. The CBL/VDL measurement provides an azimuthal average of the cement quality; therefore, measurement cannot detect a channel or any defects in the cement body (such as fractures).
4.	**Double casing**	Interpretation of CBL in double casing strings is very difficult: is only possible when the casings are centred perfectly and the cement bond is very good. The main reason is that, the low frequencies at which the tool operates makes the wavelengths too long to be able to differentiate between two casings

3.6 Ultrasonic cement bond logging

Perhaps the most significant development in cement evaluation technology was the ultrasonic logging tools. Ultrasonic type tools such as the Ultrasonic Sonic Imaging Tool[1] are designed to measure the acoustic impedance of the material on the outer surface of the casing. This is accomplished by using a transducer to project a short pulse of acoustic energy with a bandwidth of 200kHz to 700kHz toward the casing. The transducer emits high frequency ultrasonic pulses that travel through the well fluids and into the casing wall, resonating the casing in the thickness mode. The transducer then becomes a receiver and measures the returning echo from the casing. The returning waveform is the summation of the echo waveform from the original burst, and an exponentially decaying waveform from the resonant energy trapped between the inner and outer casing walls.

The analysis of the returning wave can be performed in several different ways with the outputs being acoustic impedance of the material on the outside surface of the casing and thickness of the casing. Current versions of the ultrasonic tools have a rotating transducer that provides full radial coverage of the casing circumference. These tools have far better vertical and radial resolution than the CBL type tools. Furthermore, the interpretation of the cement quality is not dependent on the specific acoustic properties of the cement. The ultrasonic interpretation is sensitive to the acoustic properties of the fluids [5].

Application and limitations

Ultrasonic tools provide information both on the cement and on the casing string and can therefore be used for both cement and corrosion evaluation (see section 3.7 for an overview of ultrasonic corrosion measurements).

Case study [5]

During production through a 5½" production tubing inside 9⅞" casing (which was set in 13⅜" casing), there was pressure increase on the 5½" × 9⅞" annulus. It was decided to pull the 5½" production tubing to evaluate the cause of the sustained pressure increase. The 5½" tubing (and completion) was cut above the packer, but could not pulled.

The operator ran cement bond and stuck pipe logs to identify the reason for the stuck pipe. The logs indicated that the 5½" tubing was damaged (it had pinched across the interval 14,880-14,810ft) (Refer to Figure 8).

[1] Mark of Schlumberger

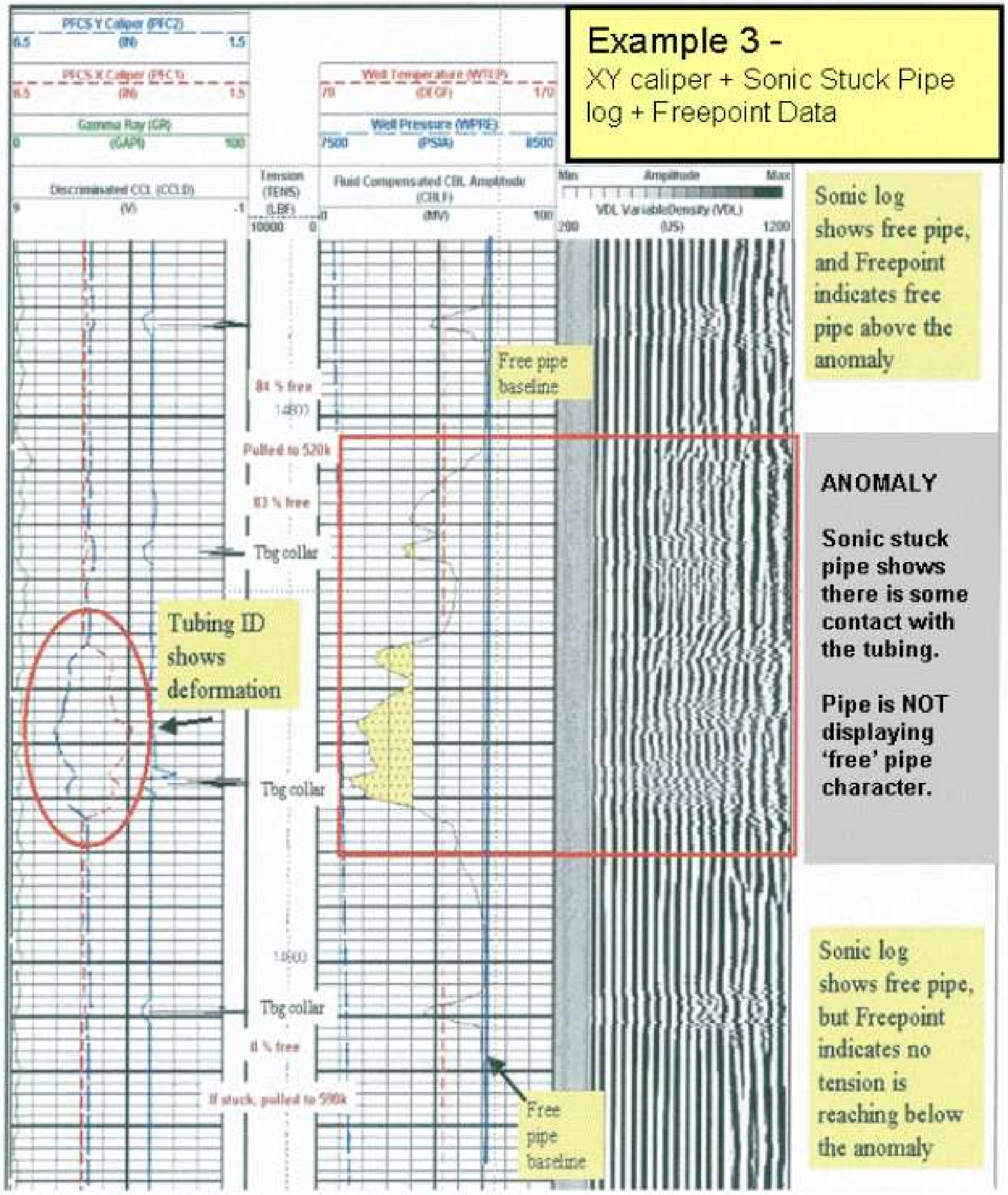


Figure 8: Cement bond logs show deformation. (Source: [5])

The 5½" production tubing was eventually cut above the stuck point and pulled free.

The operator then decided to run the Isolation Scanner[2] (ultrasonic cement bond measurement) in order to assess the condition of the 9⅞" and 13⅜" casings above the cut point. Figure 9 shows the relative positions of the casings as measured by the tool (at depth 243m).

[2] Mark of Schlumberger

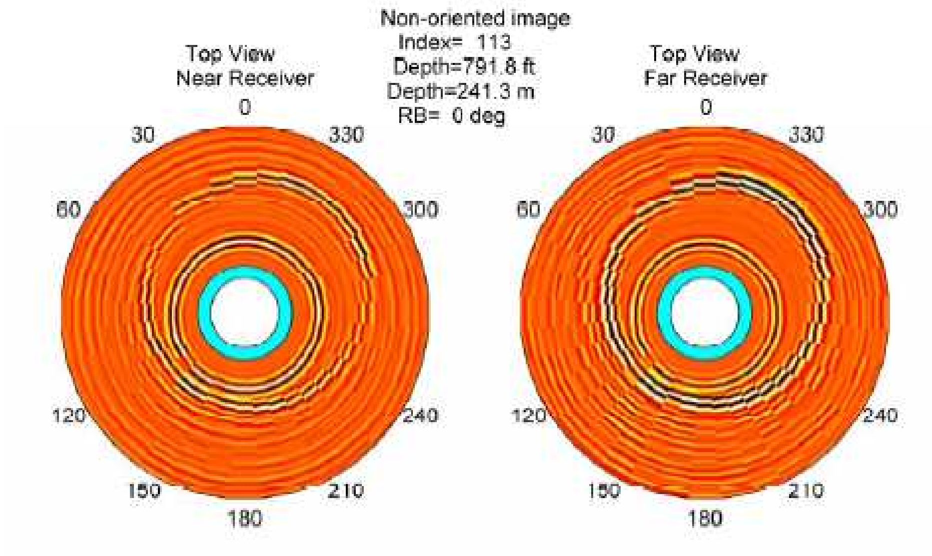


Figure 9: Result of ultrasonic (Isolation Scanner) logging.

Upper wellbore section with two casing strings showing relative position of the casing within the borehole. This shows that the 9⅞” casing is not well-centralised in the 13⅜” casing.(Source: [5])

This measurement was performed along the length of the well. The log measurement indicated that there were solid deposits on the pipe at 14,500ft and not a pipe collapse. These solid deposits, not collapse of the production casing, were adduced to be the reason for the stuck pipe.

3.7 Ultrasonic corrosion logs

Ultrasonic corrosion tools are a derivative of the ultrasonic cement bond measurements and a marked improved on mechanical caliper measurements. They use a rotating ultrasonic transducer to measure the echo time of a high-frequency (2MHz) ultrasonic pulse. Signal arrivals are then analysed to provide the casing thickness and surface condition images.

Precise radius and thickness measurements enable quantifying the depth of an anomaly. The tool has the resolution and sensitivity needed to measure pits and other anomalies down to diameters as small as 0.3*in* on either the *inside* or *outside* surface. The tool makes absolute measurements so that corrosion and other casing anomalies can be identified and measured without reference to a base log. Figure 10 shows the ultrasonic casing imaging tool.

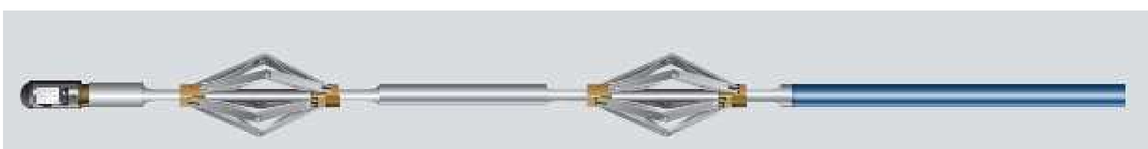


Figure 10: Ultrasonic casing imaging tool. (Source: Schlumberger)

Application and limitations

Accuracy is essential	The ultrasonic casing corrosion measurement is applicable in cases where good azimuthal coverage of the pipe is required or where corrosion on the outside surface of the casing is suspected.
Excessive corrosion	Excessively corroded pipe may distort the measurements of the tool.
Cannot be run in gas	Since the tool relies on the transmission of acoustic waves from the tool to the formation, it (the tool) needs to be run in a liquid. Therefore, it can only be run in natural gas (or CO_2 wells) if the well is killed with brine. This, in turn, may cause undesirable reduction in injectivity because the brine may alter the gas relative permeability in the near wellbore.

3.8 Electromagnetic corrosion measurement

Electromagnetic corrosion monitoring tools in use today rely on one of two physical principles: flux leakage and electromagnetic induction [6]. A flux leakage tool uses a permanent or electromagnet to magnetise the pipe to near saturation. Near a pit, hole or corrosion patch, some of the magnetic flux leaks out of the metal; this flux leakage is detected by coils on the tool's pad-mounted sensors. A flux leakage tool can sense defects on the inside or outside of the casing, but since the magnet must be as close as possible to the pipe, a casing examination requires operators to pull the tubing out of the hole. In addition, flux leakage tools are good at measuring sudden thickness changes, but they are not effective if the corrosion is constant or varies slowly over a whole section of pipe.

An electromagnetic induction tool, on the other hand, uses a principle of operation similar to that of a transformer with losses. A transformer's primary coil generates a tome-varying magnetic field that flows through a magnetic coil to induce voltage in its secondary coil. In comparison, the tool's transmitter coil, acting as a primary coil, generates a magnetic field whose flux is guided by the casing. This magnetic flux induces a voltage in a secondary or receiver coil.

The flux guide provided by the casing is lossy; energy is lost or dissipated in the medium because of the currents induced in the casing metal. The tool measures these losses to determine the geometrical, electrical and magnetic properties of the casing, including the presence of corrosion or pitting in the pipe.

Figure 11: Electromagnetic corrosion tool. (Source: [6])

Application and limitations

The electromagnetic tool can be run in any type of fluid (liquid or gas) and in a wide range of tubing/casing sizes (2⅞" to 13⅜").

Case study: GDF SUEZ K12B [6]

GDF SUEZ E&P Nederland B.V. operates the K12-B gas field located about 150km northwest of Amsterdam. Since January 2005, GDF SUEZ has been injecting CO_2 from the produced gas into the K12-B6 well. Multifinger caliper measurements in the well had shown anomalous results: measured pipe i.d. increased and then decreased with repeated surveys. Coverage of the caliper fingers was only 25% to 30% of the 4½" o.d. tubing.

GDF SUEZ then decided to run an electromagnetic induction corrosion survey in order to understand if there was any potential corrosion issue. Figure 12 below illustrates the result of the survey.

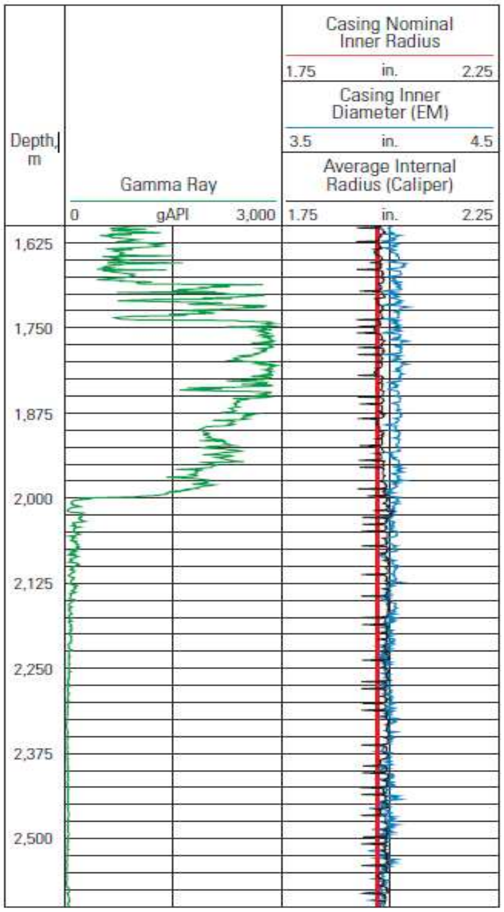


Figure 12: Results of the electromagnetic corrosion measurement in GDF SUEZ K12B-B6.

Indication of scale in 4½" pipe: Below about 2,033m, the measurement of inner radius from the caliper tool (Track 2, black) agrees with the electromagnetic tool readings. Above that point, the EM measurement continues to indicate the same ID, but the caliper tool indicates a smaller radius. The large increase in gamma ray response (track 1) is interpreted as resulting from a build up of scale containing naturally-occurring radioactive material [6].

The electromagnetic measurement indicated that the tubing was still in good condition; there was no indication of corrosion. However, the log showed the presence of scale.

Build-up of scale inside the pipe affects corrosion-monitoring tools differently. Caliper tools will ride along scale indicating an ID that is too small. The effect on an EM-based measurement depends on the composition of the scale itself. In the case of non-conducting, non-magnetic scale such as calcium carbonate, there is no effect unless the build-up is thick enough.

Case study: Equity Energy [6]

Equity Energy operates the onshore Kampung Baru gas field in Sulawesi, Indonesia. The produced gas contains both carbon dioxide (CO_2) and hydrogen sulphide (H_2S). The field has three producing wells that have been operating for twelve years. Because of the potential for corrosion, the wells in the field were logged using the electromagnetic induction tool.

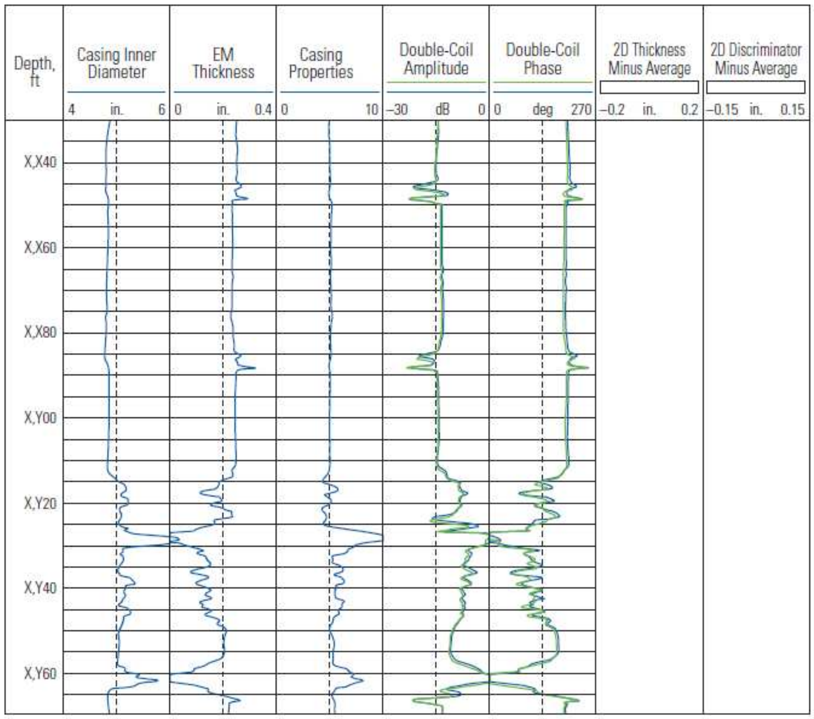


Figure 13 Results of the electromagnetic corrosion measurement (Equity Energy).

Corrosion is at perforations in kampong Baru field in well producing H_2S with natural gas. The 2D thickness image (track 6) shows metal loss below X,Y15ft, while the 2D discriminator log (track 7) shows only the perforations. This observation indicates that the loss is on the outside wall of the casing. Higher in the interval, the log response is evidence of casing collars and pipe manufacturing patterns: pipe is manufactured from flat steel and then rolled and welded, creating seams that are “seen” by the tool [6].)

In another interval in the same well, the electromagnetic induction tool, average-thickness measurement, revealed metal loss from the outer string of the 9⅝” casing.

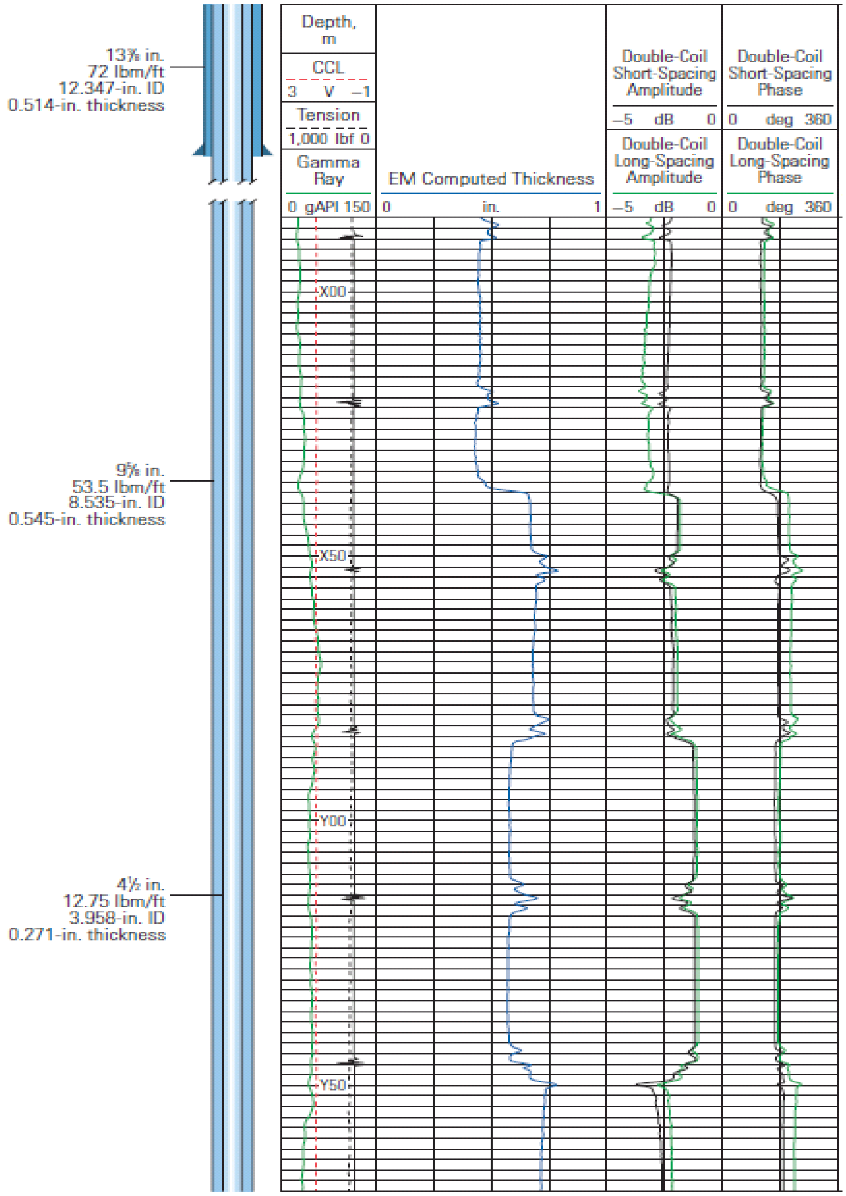


Figure 14 Results of the electromagnetic corrosion measurement (Equity Energy)

Evidence of metal loss in outer casing. The logged sections consist of 4½" tubing and 9⅝" casing. The computed thickness of the double strings of pipe is significantly less than nominal value above X40m (track 1), but there is no evidence of loss on the 2D discriminator log (track 5), indicating that the loss is not on the inside wall of the tubing. The log responses are interpreted as loss of thickness on the outer wall of the 9⅝" casing in these sections [6].)

3.9 Corrosion protection evaluation tool

Sometimes, wells are cathodically protected. In order to assess the performance of cathodic protection, a Corrosion Protection Evaluation Tool may be run. The resulting log describes how well the cathodic protection is performing and advises whether new wells need cathodic protection.

The tool measures casing potential using four electrodes which contact the walls of the casing. The tool outputs are axial current, radial current density, potential difference, casing thickness, and corrosion rate.

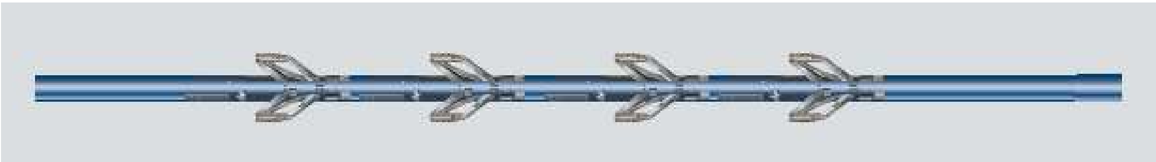


Figure 15: Cathodic protection evaluation tool. (Source: Schlumberger)

3.10 Downhole cameras

Downhole cameras can be used to monitor well integrity if the wellbore is filled with gas or any other clear fluid. They are relatively cheap to run and can fit into most tubing sizes. The main advantage of running cameras is obvious: they give a visual image—as opposed to interpreted image—of the wellbore. However, if the tubing surface is covered with corrosion products, under-deposit corrosion may not be visible through the camera.

3.11 Permanent ultrasonic corrosion monitoring

This technique uses high frequency sound waves transmitted through the metal and detects the reflected sound from the other metal surfaces to measure the wall thickness of tubing. Ultrasonic apparatus can be used for monitoring the condition of well tubing and well casing strings to indentify the onset and location of corrosion [7]. The apparatus uses an array of piezoelectric transducers (26) positioned around the circumference of the pipe and a microprocessor (28) that controls the signals communicating with the instrumentation apparatus located at the earth's surface. The microprocessors at varying locations along the string can be electrically connected to the surface control and instrumentation apparatus by conductor cables and/or by wireless using the pipe string.

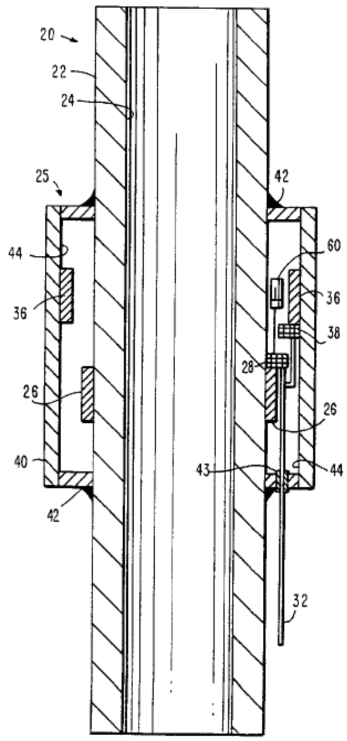


Figure 16: Permanent ultrasonic measurement [7]

Application and limitations

As far as we are aware, there is no published case in which this technique was applied in well environments.

3.12 Electrical resistance sensor

The electrical resistance of a metal specimen can be used to monitor the corrosion of the metal, because the resistance of the metal changes with the cross-section area [8]. A tool for monitoring corrosion levels within a wellbore was invented by Waterman et al.[9, 10]. The sensor uses the same material as the tubing and is positioned to allow the fluid within the wellbore to flow over the sensor at the same rate as fluid flows over the tubing. A reference element is incorporated into the corrosion sensor to provide temperature compensation. A processor reads and stores the data at programmable time intervals. The probe can be connected to a computer for downloading of the raw data. This technique is applied downhole for corrosion monitoring [9]. The limitation of the ER sensor is the low sensitivity and it can be used only for uniform corrosion. It may give wrong results if corrosion products are conductive and deposit on the surface.

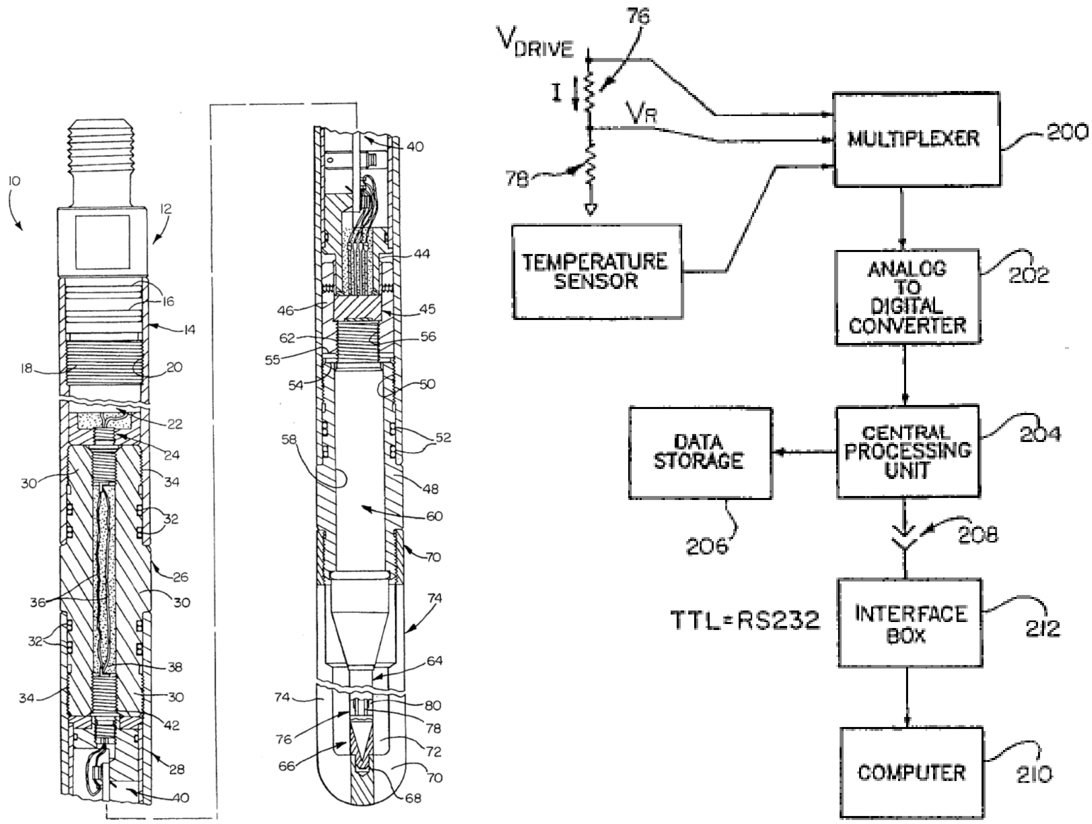


Figure 17: Electrical resistance sensor [10]

3.13 Electrochemical sensors

Electrochemical sensors such as electrochemical noise measurements (EN) and linear polarization resistance (LPR) can be used to monitor the corrosion of tubing and casing steel downhole. Linear polarization measurements can be performed using the same materials as the tubing steel to form a three-electrode cell (working, reference and counter electrodes) in the downhole. EN and LPR monitoring systems were used in Downhole wireline corrosion monitoring at oil wells (except gas wells) by Saudi Aramco. The system operates at high temperatures (> 150℃).

The polarization probe data are difficult to interpret because of oil/water emulsions and turbulent flow [11].

Figure 18: Electrochemical sensors. (Source: Intertek: www.intertek.com)

3.14 Bio-sensor

One special type of corrosion that needs special attention is bio-corrosion or MIC (microbiologically influenced corrosion). This extremely rapid form of local corrosion will be covered in more detail at a later stage in the Cato-2 program. A quick survey of the available literature shows that there are no commercial sensor systems to monitor MIC. However, there are a few systems that could give part of the solution. For example, Rohrback Cosasco Systems developed a Bio-probe (Model 6215) that provides a retractable means of collecting samples of bacteria in processes at pressures up to 10.3MPa and temperatures up to 260ºC. The Bio-Probes are used to suspend sample elements in the area to be monitored. Insertion of the Bio-Probe can be adjusted to permit electrodes positioning at precisely the desired point within the process. Standard lengths are available in 18, 24, 30 and 36 inches.

The limitation is that a coupon used for checking biofilm formation on steel surfaces is consumed and requires regular retrieval and ancillary analysis. So far it is not known if this probe can be used in downhole applications.

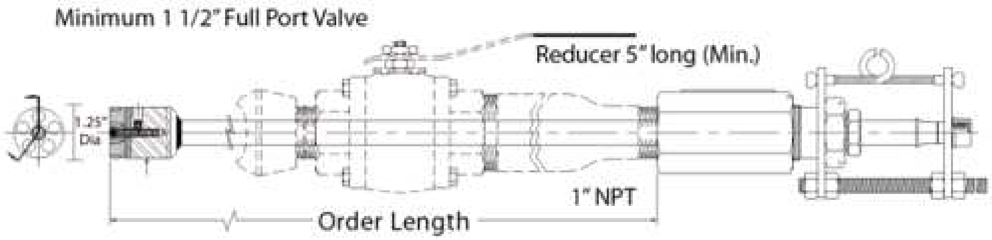


Figure 19: Bio-Probe (Model 6215). (Source: http://www.cosasco.com/microbiologically-influenced-corrosion-monitoring-c-118-l-en.html)

4 Future CATO-2 work

Most of the tools described in section 3, such as CHDT, DTS, caliper, and electromagnetic sensors, have deployed either in CO_2 or oil/gas wells. Some tools, however, such as the permanent ultrasonic tools, are relatively new inventions. The permanent ultrasonic monitoring tool, for example, which was designed for long-term monitoring of oil wells, is still largely in the concept phase; it is not clear that it can be used in for long-term monitoring of CO_2 storage wells. This will be investigated as part of the workscope for Years 2-5.

In addition, we will analyse the sensitivity and robustness of the electrochemical sensors (for permanent corrosion monitoring of the casing steel) in the future scope of the project.

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