

Casing Corrosion Measurement to Extend Asset Life

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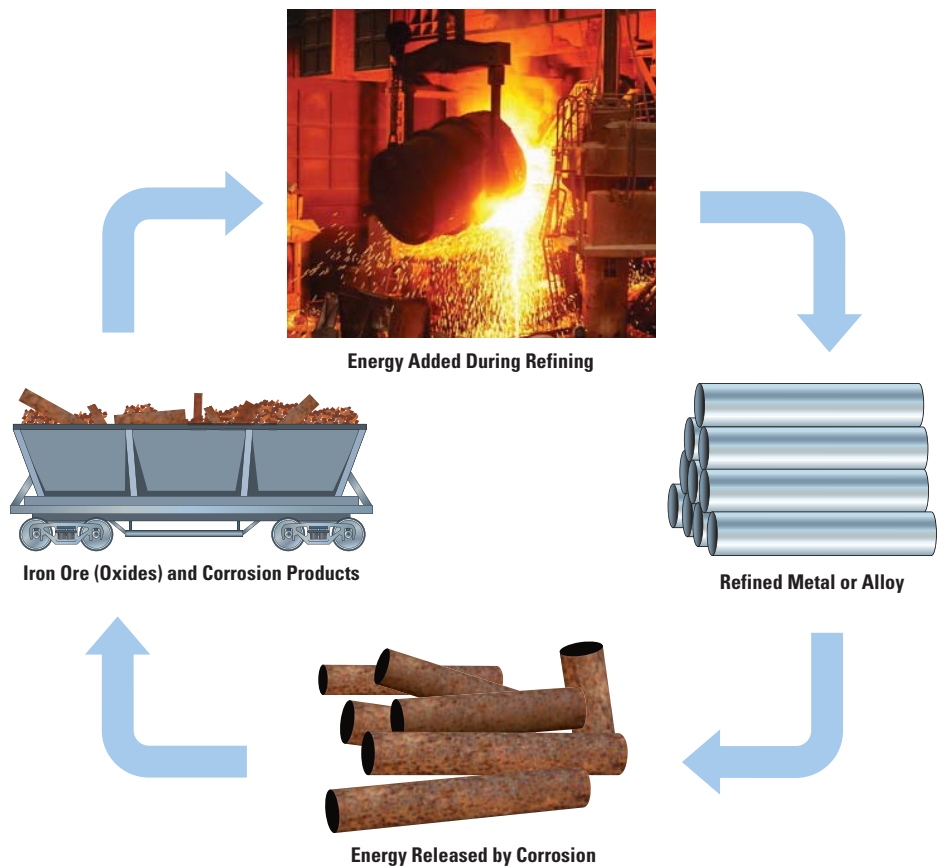
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Corrosion challenges are not new to the oil and gas industry, and producers are continually seeking new ways to keep corrosion at bay. Experts have made advances in corrosion monitoring along several fronts. The implementation of these technologies may help operators optimize infrastructure utilization, maximize production and minimize negative impact on the environment.

Oil and gas companies typically serve two masters. On the one hand, profitability dictates that producers maximize long-term production while minimizing operating expenditures. On the other hand, environmental compliance requires that companies conduct exploration and production operations safely and in an environmentally responsible manner.



^ Typical refining-corrosion life cycle for metals. Energy is stored in a metal as it is refined from its naturally occurring state (such as iron ore) to an alloy. Corrosion takes place spontaneously and releases the stored energy, which returns the metal back to a lower energy state. That process can be slowed by the application of one or more field-based mitigation measures.

The two mandates share a common enemy. Corrosion, which is the natural tendency for materials to return to their most thermodynamically stable state by reacting with agents in the surrounding environment, attacks almost every component of a well. Wells are constructed primarily of steel, which is refined from naturally occurring iron ore. The process of refining ore into a steel alloy suitable for oil and gas drilling and production takes the ore to a higher energy state. Corrosion reverses this process and brings metal back toward its original, lower energy state (previous page).¹

The process of corrosion, which begins the moment steel is cast, is accelerated in the oil field by the presence of acidic species—such as hydrogen sulfide [H₂S] or carbon dioxide [CO₂]—in many formation fluids and by the elevated temperatures and pressures in producing formations. The consequences of corrosion include a reduction in wall thickness and loss of strength, ductility and impact strength in the steel that makes up the downhole tubulars, wellheads and surface piping and downstream processing equipment (right).

Failure to address corrosive attacks early impacts well profitability because operators must then implement potentially expensive, and perhaps extensive, mitigation methods. Not only does mitigation increase operating expenses, it may force operators to shut a well in for some period of time. In the worst cases, unattended corrosion can lead to a leak or rupture, which may threaten the safety of oilfield personnel, lead to production losses and introduce hydrocarbons and other reservoir fluids into the environment.

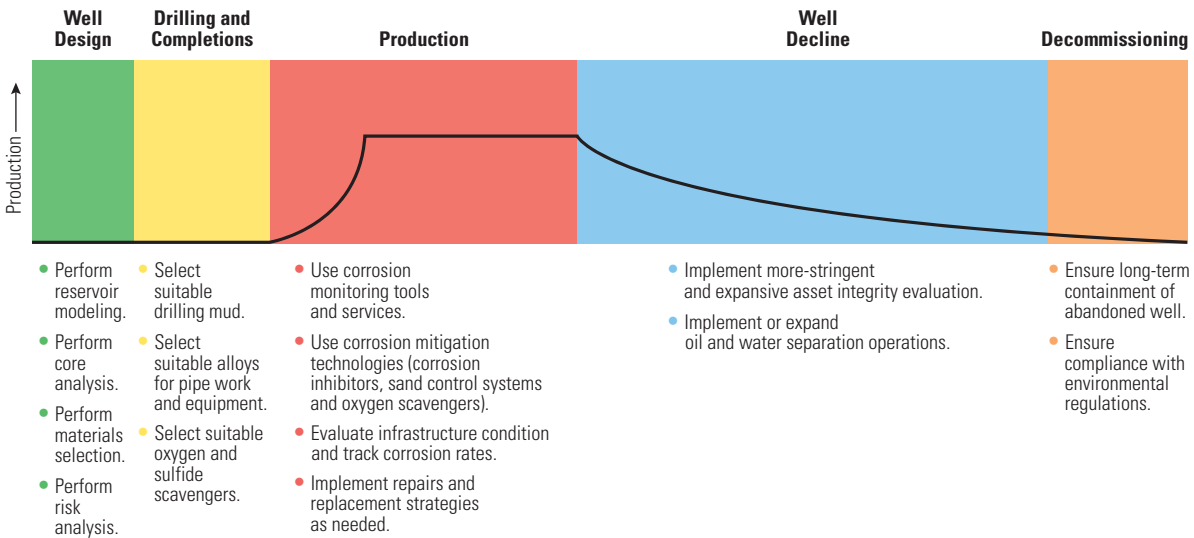
The total annual cost of corrosion in the US alone is estimated at approximately US\$ 1.4 billion, of which US\$ 589 million is surface pipeline and facility costs, US\$ 463 million is downhole tubing expenses and US\$ 320 million is capital expenditures.² These estimates do not factor in the fines that may be levied by government regulatory agencies against operators that experience a corrosion-related discharge of production fluids into the environment. The costs and risks may also increase as hydrocarbon sources are discovered in more-challenging environments—deeper reservoirs with higher temperatures and pressures that contain higher concentrations of

Problem	Cause of Corrosion	Control Methods	Monitoring
Oxygen corrosion	<ul style="list-style-type: none"> • Oxygenated water • Internal attack • External attack 	<ul style="list-style-type: none"> • Resistant materials • Oxygen scavengers • Oxygen stripping • Improved seal design • Coatings • Cathodic protection 	<ul style="list-style-type: none"> • Water and oxygen sampling • Iron counts • Corrosion probes • Oxygen sensors • Coupon surveys • Wall thickness surveys • Visual internal inspections • Visual surveys
Hydrogen sulfide corrosion pitting	<ul style="list-style-type: none"> • Water from production aquifer or other deep aquifer • Water contaminated by stripping or lift gas 	<ul style="list-style-type: none"> • Degassing at low pressures • Control of contaminated gas • Use of resistant materials 	<ul style="list-style-type: none"> • Probes • Iron counts • Wall thickness surveys
Sulfate-reducing bacteria (SRB)	<ul style="list-style-type: none"> • Anaerobic fluids • Stagnant fluids • Conditions under scales or other deposits 	<ul style="list-style-type: none"> • Biocides • Chlorination 	<ul style="list-style-type: none"> • Anaerobic bacteria counts • Chlorine residuals measurements
Carbon dioxide corrosion	<ul style="list-style-type: none"> • Water from production aquifer or other deep aquifer • Water contaminated by stripping or lift gas 	<ul style="list-style-type: none"> • Degassing at low pressures • Control of contaminated gas • Use of resistant materials 	<ul style="list-style-type: none"> • Probes • Iron counts • Wall thickness surveys
Hydrogen sulfide stress corrosion cracking Hydrogen-induced cracking	<ul style="list-style-type: none"> • Produced fluids containing hydrogen sulfide • Anaerobic systems contaminated with SRB 	<ul style="list-style-type: none"> • Suitable materials 	<ul style="list-style-type: none"> • Materials quality control
Acid corrosion	<ul style="list-style-type: none"> • Stimulation and cleaning acids 	<ul style="list-style-type: none"> • Acid inhibitors 	<ul style="list-style-type: none"> • Acid inhibitor checks
Galvanic (bimetallic) corrosion	<ul style="list-style-type: none"> • Two metals with different ionic potentials in a corrosive medium 	<ul style="list-style-type: none"> • Electrical isolation of metals (cathodic coating) • Improved design 	<ul style="list-style-type: none"> • Design reviews
Pitting corrosion (rapid corrosion at defects in inert surface film)	<ul style="list-style-type: none"> • Immersion • Inert surface films 	<ul style="list-style-type: none"> • Materials selection 	<ul style="list-style-type: none"> • Equipment inspections
Subdeposit corrosion	<ul style="list-style-type: none"> • Wet solids deposits • Biofilms • Porous gaskets 	<ul style="list-style-type: none"> • Pigging • Biocides • Improved sealing and design • Minimum velocity design 	<ul style="list-style-type: none"> • Equipment inspections • Bacteria counts
Crevice corrosion	<ul style="list-style-type: none"> • Poor design • Imperfections in metal 	<ul style="list-style-type: none"> • Improved design • Materials selection 	<ul style="list-style-type: none"> • Equipment disassembly and inspections • Leak detections
Chloride corrosion (rapid cracking on exposure to hot chloride media)	<ul style="list-style-type: none"> • Salt solution • Oxygen and heat 	<ul style="list-style-type: none"> • Materials selection 	<ul style="list-style-type: none"> • Equipment inspections • Oxygen analyses
Fatigue	<ul style="list-style-type: none"> • Rotating equipment • Wave-, wind- or current-induced loading 	<ul style="list-style-type: none"> • Vibration design 	<ul style="list-style-type: none"> • Equipment inspections

1. For more on the corrosion process: Brondel D, Edwards R, Hayman A, Hill D, Mehta S and Semerad T: "Corrosion in the Oil Industry," *Oilfield Review* 6, no. 2 (April 1994): 4–18.

2. Koch GH, Brongers MPH, Thompson NG, Virmani YP and Payer JH: "Corrosion Costs and Preventive Strategies in the United States," Washington, DC: US Department of Transportation Federal Highway Administration, Office of Infrastructure Research and Development, Publication no. FHWA-RD-01-156, September 2001.

^ Summary of corrosion problems and solutions. In the oil field, corrosion is pervasive and takes many forms. By properly identifying the source of corrosive attack, an operator can implement a suitable corrosion monitoring and control program.



▲ Corrosion considerations at each stage of the asset life cycle. During each stage of a well's life, engineers must consider operational factors to keep corrosion at bay and minimize the threat of production fluid leaks into the surrounding environment.

acidic gases—which may present more-aggressive corrosion environments.

The industry has advanced several methods to combat corrosion and extend the operating life of a well. These may be broadly classified into four main categories:

- metallurgy—substituting traditional wellbore tubulars with those manufactured with a corrosion-resistant alloy (CRA)
- chemical—modifying production fluids to reduce the intensity of corrosive attacks or creating barriers that isolate the metal from produced fluids through the application of a protective coating
- injection—pumping surfactant-base fluids that aggregate at the metal surface and block metal-water contact, thus inhibiting corrosion
- cathodic protection—using DC current to create impressed cathodic protection.³

The first option—upgrading tubulars to those composed of CRA—may be cost prohibitive on a large scale. In the US alone, there are more than 100,000 producing oil and gas wells with casing, tubing, wellheads, processing equipment and gathering lines.

Manufacturers may employ another mitigation option: applying permanent coatings, which combat corrosion by forming a resistant barrier between the corrosive fluid media and the metal surface. Many coating types exist and are generally categorized as follows:

- metallic—zinc, chromium and aluminum
- inorganic—enamels, glasses, ceramics and glass-reinforced linings
- organic—epoxies, acrylics and polyurethanes.⁴

As with CRAs, coatings may promise a longer operating life with reduced maintenance, but they come at a cost premium.⁵

Operators may use inhibition by chemical means during the production stage of the well to mitigate corrosion on the internal surface of piping and equipment. Corrosion inhibitors are typically surfactant-base chemical formulations that are added to the production stream in concentrations ranging from tens to several hundred parts per million (ppm). The inhibitor molecules migrate and collect at surfaces; in the case of a well's production infrastructure, the molecules collect at the metal surface to form a barrier between it and the corrosive fluid phase. In this way, they act in a manner similar to that of a coating, but at a lower cost than that of a permanent coating or a CRA. Unlike a coating, a corrosion inhibitor must be reapplied to replenish the inhibitor film that is degraded or washed away by the flowing action of the production stream.⁶

Corrosion prevention through cathodic protection works by forcing anodic areas of the metal—those susceptible to corrosive attack—to become cathodic or noncorrosive. To accomplish this, operators apply a DC current through the metal to counteract the corrosion current—a technique known as impressed cathodic protection (ICP)—or use sacrificial anodes, which are composed of metal that has a greater corrosion tendency than the metal to be protected.⁷

This article focuses on corrosion monitoring and measurement techniques for downhole infrastructure during production. Case studies from

the Middle East demonstrate how corrosion monitoring tools and mitigation technologies have helped operators identify the location and severity of corrosion in the subsurface infrastructure, which informed each company's choice of mitigation solution.

Corrosion and the Life Cycle

Corrosion is a major concern throughout the life of a well, and specific considerations and mitigation strategies are required at each stage. Asset personnel usually begin making corrosion mitigation decisions for a well before drilling. During the well design stage, the operator conducts comprehensive reservoir studies, which include reservoir simulation modeling, core studies and fluid analysis from offset well data. Engineers use the information obtained from these studies to develop risk assessments for corrosion threats in subsequent stages of the well. Engineers then develop and implement mitigation strategies that include appropriate materials selection, optimal production rates, monitoring programs and corrosion inhibitor treatments (above).

During the drilling process, operators focus corrosion mitigation strategies on extending the working life of drillpipe, which is exposed to high operational stresses as well as potentially corrosive drilling muds and formation fluids. The drillpipe may undergo one of several types of corrosion mechanisms, including localized pitting, in which H₂S, chloride salts or oxygen in water-base drilling muds cause a corrosion rate that exceeds 25 cm [9.8 in.] per year.⁸ Other corrosion sources

include the presence of CO₂ at a partial pressure of 20 to 200 kPa [3 to 30 psi] or greater, microbologically influenced corrosion (MIC) caused by the presence of certain bacteria (microbes) in produced fluids and crevice corrosion in which localized corrosion rates at metal-to-metal or metal-to-nonmetal interfaces, such as at joint couplings or gaskets, reach elevated levels and lead to pitting or cracking.⁹

The common ingredient in these various corrosion events is drilling mud. To prevent drilling muds from becoming corrosive, mud engineers use specific chemical treatments in the mud. These treatments focus on keeping the pH of the mud within an acceptable range—typically between 9.5 and 12—by dosing it with alkali or adding oxygen scavengers to reduce dissolved oxygen levels below 1 ppm or by adding sulfide scavengers that eliminate H₂S from the mud system.¹⁰

The completion phase of a well refers to the assembly and installation of downhole tubulars and equipment such as packers and artificial lift pump systems. Information collected during the well planning stage, including the temperature and pressure of the reservoir and the composition of the production fluids, helps inform the operator's decision on corrosion mitigation measures to be included in the completion. For example, anticipation of H₂S or CO₂ production may lead the operator to use CRAs in the completion casing strings, control valves, permanent downhole gauges and hydraulic and electric control lines.¹¹

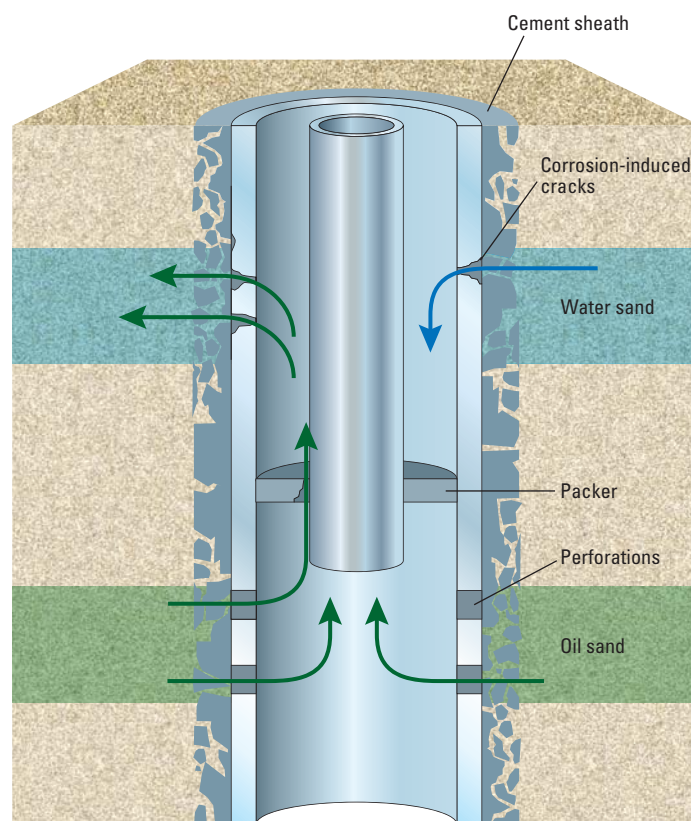
At the end of the well's life cycle, hydrocarbon production levels fall—often with a corresponding rise in water production rates—to a point at which the well is no longer profitable and the operator must plug and abandon (P&A) it. The operator's corrosion mitigation strategies shift to permanently prevent reservoir fluid releases to the environment long after the well is abandoned. The basics of a P&A operation include removing completion hardware, setting isolation plugs and squeezing cement into the annular spaces at various depths to permanently seal off producing and water-bearing zones.¹²

P&A operations represent a pure cost, which motivates operators to conduct these activities as quickly and efficiently as possible. At the same time, a P&A job must be carried out with strict adherence to government regulatory requirements. While these regulations vary widely in their severity and punitive measures, should a regulator find a leak in a previously abandoned well, it is the responsibility of the operator to return to make any necessary repairs and replug the well—often at a significantly higher cost than that of the original P&A operation.

Operators realize a profit during a well's production stage, which may last from only a few years to several decades. During this stage, corrosion mitigation efforts are generally focused on keeping corrosion rates low and preventing leaks (below). The operator must continually

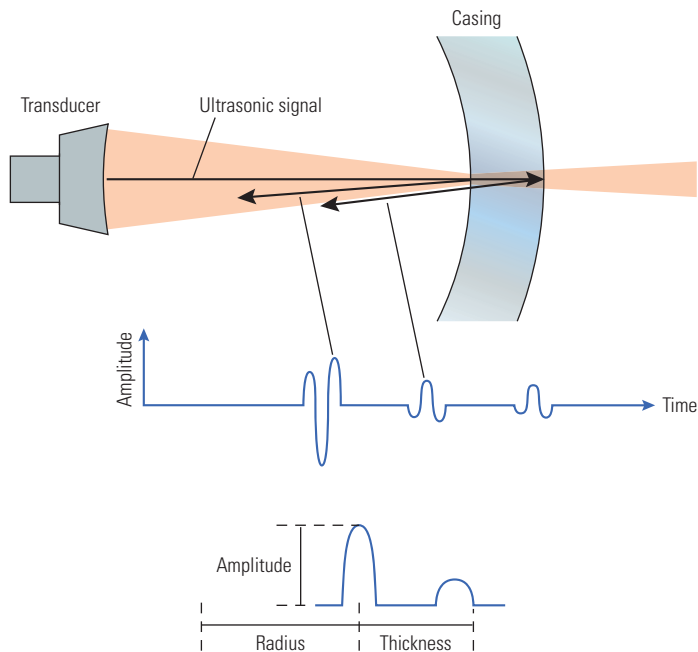
monitor and inspect the infrastructure to gauge the integrity of downhole and surface piping and equipment and the effectiveness of the mitigation.

Companies use a variety of corrosion monitoring techniques in oil and gas fields. Techniques are



▲ Corrosion's impact on casing integrity. Casing leaks typically arise from excessive corrosion in the production system. These leaks, which can prove costly and environmentally damaging, may allow additional formation water and sand to enter the production string of the well (blue arrow). Alternatively, crossflows (green arrows) may result, which can be difficult to characterize and treat, and in severe cases, the operator may have to pull and replace the entire casing string.

3. Nalli K: "Corrosion and Its Mitigation in the Oil & Gas Industry—An Overview," *PetroMin Pipeliner* (January–March 2010): 10–16.
4. Heim G and Schwenk W: "Coatings for Corrosion Protection," in von Baekman W, Shwenk W and Prinz W (eds): *Handbook of Cathodic Corrosion Protection*, 3rd ed. Houston: Gulf Coast Publishing Company (1997): 153–178.
5. Craig BD, Lane RA and Rose DH: *Corrosion Prevention and Control: A Program Management Guide for Selecting Materials, Spiral 2*, 2nd ed. Rome, New York, USA: Advanced Materials, Manufacturing, and Testing Information Analysis Center, Alion Science & Technology (September 2006): 40.
6. Corrosion inhibitors are applied either continuously by strategically injecting them into the well or production string at a steady rate to maintain a desired concentration or through batch application, wherein a larger volume often called a batch, or slug, of inhibitor is applied into the well on a periodic basis. Continuous injection provides an added benefit in that the inhibitor can be applied without shutting in the well.
7. For more on impressed cathodic protection: Brondel et al, reference 1.
8. The corrosion rate is the thickness of metal that would be lost to corrosion in one year. This rate clearly indicates that a hole would be created in drillpipe wall in far less than a year.
9. For more on microbologically influenced corrosion: Augustinovic Z, Birketveit O, Clements K, Freeman M, Gopi S, Ishoey T, Jackson G, Kubala G, Larsen J, Marcotte BWG, Scheie J, Skovhus TL and Sunde E: "Microbes—Oilfield Enemies or Allies?," *Oilfield Review* 24, no. 2 (Summer 2012): 4–17.
10. Sloat B and Weibel J: "How Oxygen Corrosion Affects Drill Pipe," *Oil and Gas Journal* 68, no. 24 (June 1970): 77–79.
11. Saldanha S: "Intelligent Wells Offer Completion Solution for Lower Tertiary Fields," *Offshore Magazine* 72, no. 8 (August 1, 2012): 54–57.
12. For more on plug and abandonment operations: Abshire LW, Desai P, Mueller D, Paulsen WB, Robertson RDB and Solheim T: "Offshore Permanent Well Abandonment," *Oilfield Review* 24, no. 1 (Spring 2012): 42–50.



^ Basic principles of the UCI ultrasonic corrosion imager. The UCI tool uses a 2-MHz focused transducer to improve the resolution of the ultrasonic measurement. The transducer also acts as a receiver of the reflected signal and records its amplitude and time of arrival. This signal is emitted (or pulsed) through the well fluid and into the casing (*top*). As this signal encounters a discontinuity, such as the inner or outer wall of the casing (*center*), the signal is reflected back. Most of the energy is reflected in the initial echo at the inner casing wall because of the large impedance contrast between the mud and the steel; the remaining energy transmitted into the casing is again reflected at the outer wall. The signal reflected back at the inner wall can be used to evaluate the casing condition and radius. The time difference between the first two echoes can be used to determine the thickness of the casing (*bottom*). In comparison, the USI tool is more commonly used for ultrasonic pipe inspection and employs a 200- to 700-kHz unfocused ultrasonic transducer to induce a casing resonance. In the USI measurement, thickness is determined from the resonance frequency. (Adapted from Hayman et al, reference 15.)

selected based in part on the system's ease of implementation for a given application or location in the production system, the ease with which results can be interpreted and the relative severity of corrosive attack. Some corrosion measurement techniques use inline monitoring tools placed directly in the production system; these tools are exposed to the flowing production stream. Other techniques provide analysis of corrosion effects after the fact in a laboratory setting.¹³

The weight loss technique using coupons, a direct visual identification method, is a well-known and simple monitoring method. This technique exposes a specimen of material—the coupon—to the process environment for a given period of time before a technician removes it from the system and analyzes it for its physical condition and the amount of weight lost.¹⁴ The

coupon technique is advantageous because coupons can be fabricated from the same alloy that makes up the system under study, the corrosion rate can be easily calculated from the coupon's weight loss over the time of exposure and the technique allows visual verification of corrosion deposits or localized corrosion. However, if a corrosion event such as a leak occurred while the coupon was in the system, the operator could not use the coupon alone to accurately pinpoint its time of occurrence. In addition, the coupon technique is applicable only in system locations that provide easy or practical access for placing and extracting the coupon.

This second limitation makes coupon monitoring, or any visual inspection technique, essentially impossible for the well's downhole tubulars and casing strings. The remaining options are indirect measurement techniques that incorpo-

rate one or more of the various logging tools that are deployed downhole via wireline, tractor or coiled tubing.

Advances in Downhole Corrosion Monitoring

Logging techniques for monitoring downhole corrosion include ultrasonic, electromagnetic and mechanical methods that yield detailed information about the location and extent of a corrosion event. Ultrasonic monitoring employs a centralized sonde that is immersed in well fluid and uses a subassembly containing a rotating transducer to perform measurements.¹⁵ Most ultrasonic tools work by the principle of pulse echo measurement, and operators choose a transducer with the characteristics necessary for the type of measurement to be taken. Measurements include cement evaluation, openhole imaging and corrosion imaging.

A USI ultrasonic imager transducer, which transmits an ultrasonic signal at a frequency ranging from 200 to 700 kHz to make the casing resonate, is typically designed for cement evaluation and pipe inspection. The quality of the cement bond is directly related to the degree of casing resonance: A good cement bond dampens the acoustic signal and causes a low-amplitude secondary signal to be returned to the transducer; a poor cement job or free pipe allows the casing to ring and returns a higher amplitude echo. Additionally, USI measurements include 2D internal radius imaging of the casing—derived from the traveltime of the main echo from the internal surface—and the 2D casing thickness, derived from the frequency response.

Higher resolution casing measurements may be acquired with the UCI ultrasonic casing imager, which uses a focused 2-MHz transducer with improved resolution compared with that of the USI tool (*left*).¹⁶ The UCI tool records two echoes: the main echo from the internal surface of the casing and the smaller echo from the external surface. The radius and thickness of the casing are computed from the arrival times of the two echoes. The relative sizes, or amplitudes, of the two echoes are qualitative indicators of the casing condition. Although the UCI device provides a better indication of the condition of the casing than does the USI imager, use of the UCI tool is limited to operations in which the well fluid comprises brines, oil and light oil–base or water-base muds. Weighted muds produce an acoustic attenuation that is too strong to allow meaningful measurement.

Ultrasonic inspection provides several advantages as a corrosion measurement tool, including its sensitivity to both internal and external

defects and instantaneous in-field notification when a defect is encountered. In addition, the technique requires access to only one side of the material to gauge the condition of the entire object and obtain detailed exterior and interior images of the object. However, inspection is difficult for materials that are heterogeneous in composition, irregular in shape or thin; to improve the results of the inspection, technicians must prepare the internal surface prior to measurement by scraping away scale or other debris.

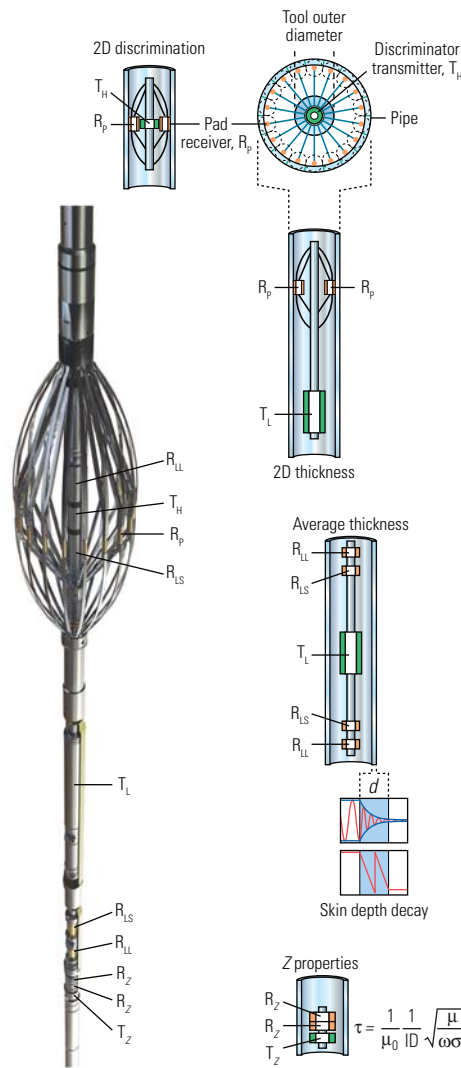
Operators may also employ another corrosion monitoring method: electromagnetic (EM)-based inspection. The basic principle of this technique involves measuring the changes to a magnetic field as it passes through a metal object; the changes are related to the condition of the material such as its thickness and its electromagnetic properties.

The industry currently uses two EM corrosion monitoring tools. The first, a flux leakage tool, magnetizes the metal object using an electromagnet. When the magnetic flux encounters a damaged section or hole in the material, part of the flux leaks out of the metal; coils on the tool's sensors detect this leakage. While this method is useful for measuring abrupt changes in pipe thickness, such as pitting or holes in the inner string, and the location of those changes, it is less effective for monitoring the steady increase of corrosion or corrosion that varies gradually over a large section of pipe or concentric casing configurations.

The second EM-based monitoring technology—the remote field eddy current tool—measures the signal of not only the primary EM field but also the secondary field from the induced eddy currents in the surrounding pipe.¹⁷

The EM Pipe Scanner electromagnetic casing inspection tool makes four distinct measurements. Using a transmitter—which operates at three frequencies—and two receivers, the EM Pipe Scanner tool makes a measurement of impedance (Z), which depends on the casing's electrical and magnetic characteristics. Using a low-frequency signal transmitter in the middle of the tool and two sets of receivers—one set above and the other below the transmitter—the tool measures the average thickness of the metal normalized by the skin depth.¹⁸

The remaining two measurements provide 2D images of the pipe; the tool obtains these measurements by pressing pad sensors against the inner wall of the pipe. One measurement uses a low-frequency signal to obtain 2D thickness information, and the other uses a high-frequency



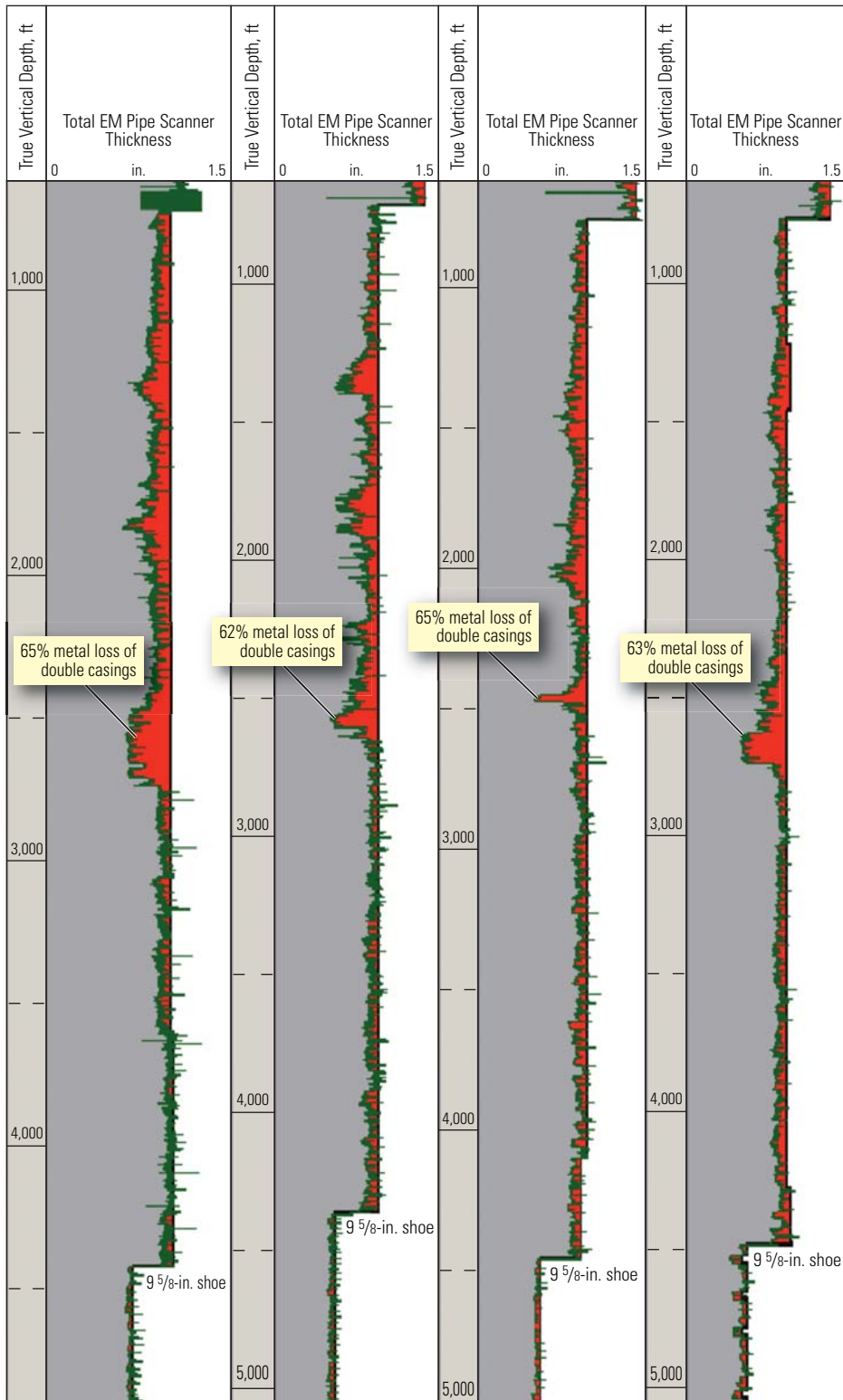
discriminator transmitter located on the tool mandrel to generate signals that do not penetrate the pipe wall, creating a 2D map that discriminates between damage on the inside and outside walls. Changes in the geometric properties of the metal, such as thickness or diameter, will cause changes to the mutual impedance, which is caused by flaws in the casing.

Since 2009, the EM Pipe Scanner tool has been used in wells around the world to detect

large holes, casing splits and corrosion-related metal loss from both the internal and external surfaces of casing; the tool can also measure loss from an outer casing string when multiple strings are present. The tool consists of 18 radial arms with pad sensors affixed around a slim mandrel. The sensors scan the interior surface and local thickness of production casing; the mandrel measurement helps identify average metal loss, damage and splits in the casing (above).

13. "Introduction to Corrosion Monitoring," *Metal Samples: Corrosion Monitoring Systems*, www.alspi.com/introduction.htm (accessed March 20, 2013).
14. "Introduction to Corrosion Monitoring," reference 13.
15. Hayman AJ, Hutin R and Wright PV: "High-Resolution Cementation and Corrosion Imaging by Ultrasound," *Transactions of the SPWLA 32nd Annual Logging Symposium*, Paris, June 16–19, 1991, paper KK.
16. Hayman AJ, Parent P, Rouault G, Zurquiyah S, Verges P, Liang K, Stanke FE and Herve P: "Developments in Corrosion Logging Using Ultrasonic Imaging," *Transactions of the SPWLA 36th Annual Logging Symposium*, Paris, June 26–29, 1995, paper WV.
17. For more on electromagnetic induction as a corrosion monitoring method: Acuña IA, Monsegue A, Brill TM, Graven H, Mulders F, Le Calvez J-L, Nichols EA,

- Zapata Bermudez F, Notoadinegoro DM and Sofronov I: "Scanning for Downhole Corrosion," *Oilfield Review* 22, no. 1 (Spring 2010): 42–50.
- Brill TM, Le Calvez JL, Demichel C, Nichols E and Zapata Bermudez F: "Electromagnetic Casing Inspection Tool for Corrosion Evaluation," paper IPTC 14865, presented at the International Petroleum Technology Conference, Bangkok, Thailand, February 7–9, 2012.
18. When the EM field encounters a conducting material such as the metal of a pipe, the amplitude of the field decreases exponentially with a characteristic rate given by the skin depth. A conductive and ferromagnetic material, such as casing, has a short skin depth. All media other than a vacuum have shorter skin depths at higher frequencies.



▲ EM Pipe Scanner logs. The logs for four Saudi Aramco wells showed varying degrees of metal loss (red), remaining thickness (gray) and total measured thickness (green) with respect to depth. A distinct pattern correlation, as well as a similar decrease in total thickness with depth, existed among the wellbores. All wells showed metal losses in the range of 62% to 65% of the outer double casings at a depth of approximately 2,500 ft. The operator used this information to anticipate similar metal loss patterns and expected a comparable level of severity of corrosion in adjacent wells not yet logged.

Operating companies can obtain these measurements without having to pull the completion tubing out of the hole, which saves rig time and intervention expense. While the engineer lowers the EM Pipe Scanner tool into the well on wire-line, tractor or coiled tubing, the tool conducts an initial high-speed reconnaissance run to flag areas of interest for detailed diagnostic scans to be performed as the tool is retrieved to the surface. The tool records a continuous log of both the average casing inner diameter and total metal thickness and provides corrosion estimates. The tool responds to overall metal thickness, allowing corrosion of the outer casing or tubing to be detected. Measurements of the inner casing metal radius are valid in the presence of most kinds of scale. Its 2½-in. diameter affords access through tight restrictions. The tool can operate in gas or liquid environments.

Forewarned Is Forearmed

In 2011, using the EM Pipe Scanner tool, Saudi Aramco conducted a well-casing corrosion monitoring campaign in a field containing both onshore and offshore wells. Initial scans of seven onshore wells indicated relatively little metal loss and confirmed that the existing ICP system was working satisfactorily. Because of the lack of a sufficiently large power supply, the offshore wells had limited ICP, which raised the possibility of higher corrosion rates.

The EM Pipe Scanner tool was deployed to determine the extent of metal loss from well casings in the offshore portion of the field and to help the operator geographically map wells exhibiting the most severe metal loss. In one campaign, in four adjacent wells that were originally completed in 1976, Saudi Aramco checked to determine whether any of these well had concentric casings that might soon leak.¹⁹ If engineers observed metal loss, they planned to analyze the loss profile for the purpose of mapping and anticipating the likelihood of casing corrosion in nearby, nonlogged wells.

The EM Pipe Scanner logs showed varying degrees of metal loss in each of the four subject wells, although the logs indicated a distinct depth correlation among them. One noticeable correlation occurred between 2,500 and 2,800 ft [760 and 850 m], where the four wells had casing metal losses ranging from 62% to 65% (left). The operator concluded that other wells in this geographic vicinity were susceptible to significant metal loss and at risk of casing leaks in this depth interval. This conclusion may guide completion decisions for future wells drilled in the area, which could include landing the outermost casing string—

typically 13 $\frac{1}{2}$ -in. casing—deeper than in the previous wells. The original landing depth of 700 ft [213 m] could be extended to a depth of 3,000 ft [914 m] to provide an additional layer of corrosion protection to the inner string. Another solution could be to add a further level of protection by running chrome alloy or coated 13 $\frac{1}{2}$ -in. casing from 1,000 ft [300 m] to 3,000 ft.

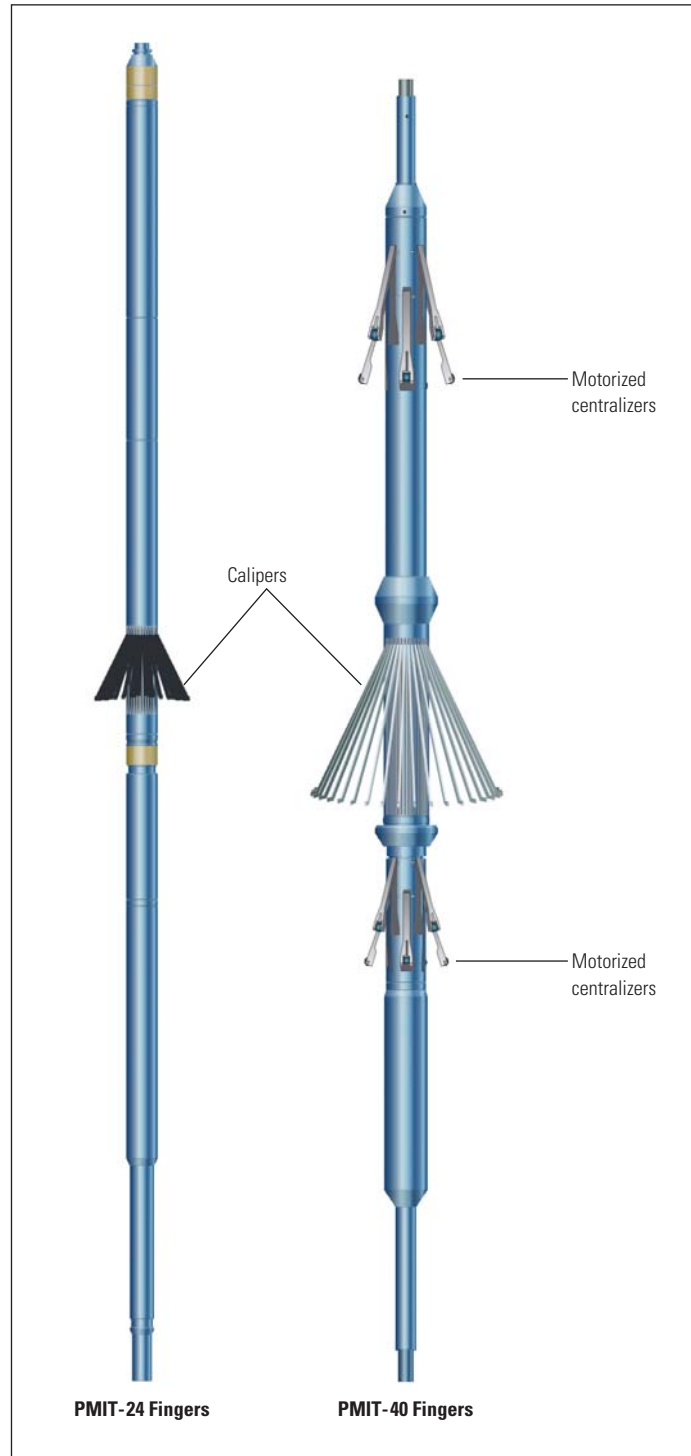
The metal loss profiles from these wells also may influence the operator's decision to implement more cost-effective and efficient workovers for repairing leaks. For example, the operator could reduce workover costs by running a cement squeeze limited to the depth of significant metal loss rather than incurring additional costs of a liner, casing patch or scab liner, which might be normally recommended if massive metal loss covered a long interval.²⁰

In addition to the acoustic and electromagnetic monitoring techniques discussed, mechanical methods are also helpful. A multifinger mechanical caliper tool uses a fundamentally different approach. Caliper tools rely on direct physical contact with the pipe wall to make measurements and to detect small changes in the tubular wall such as deformations arising from the buildup of scale or metal losses from corrosion. While they are well established for evaluating internal problems, caliper tools provide no data regarding the condition of the external wall.

The Schlumberger PipeView multifinger caliper tool for PS Platform toolstring has been deployed to investigate corrosion in many types of wells but particularly in those with excessive scale and corrosion in which acoustic-based tools cannot be run. The tool can be deployed with 24, 40 or 60 fingers and used in casing diameters ranging from 1 $\frac{1}{4}$ in. to 14 in. It provides a mechanical image of the internal tubular corrosion using 3D analysis and visualization software (right).

Measurements over Time

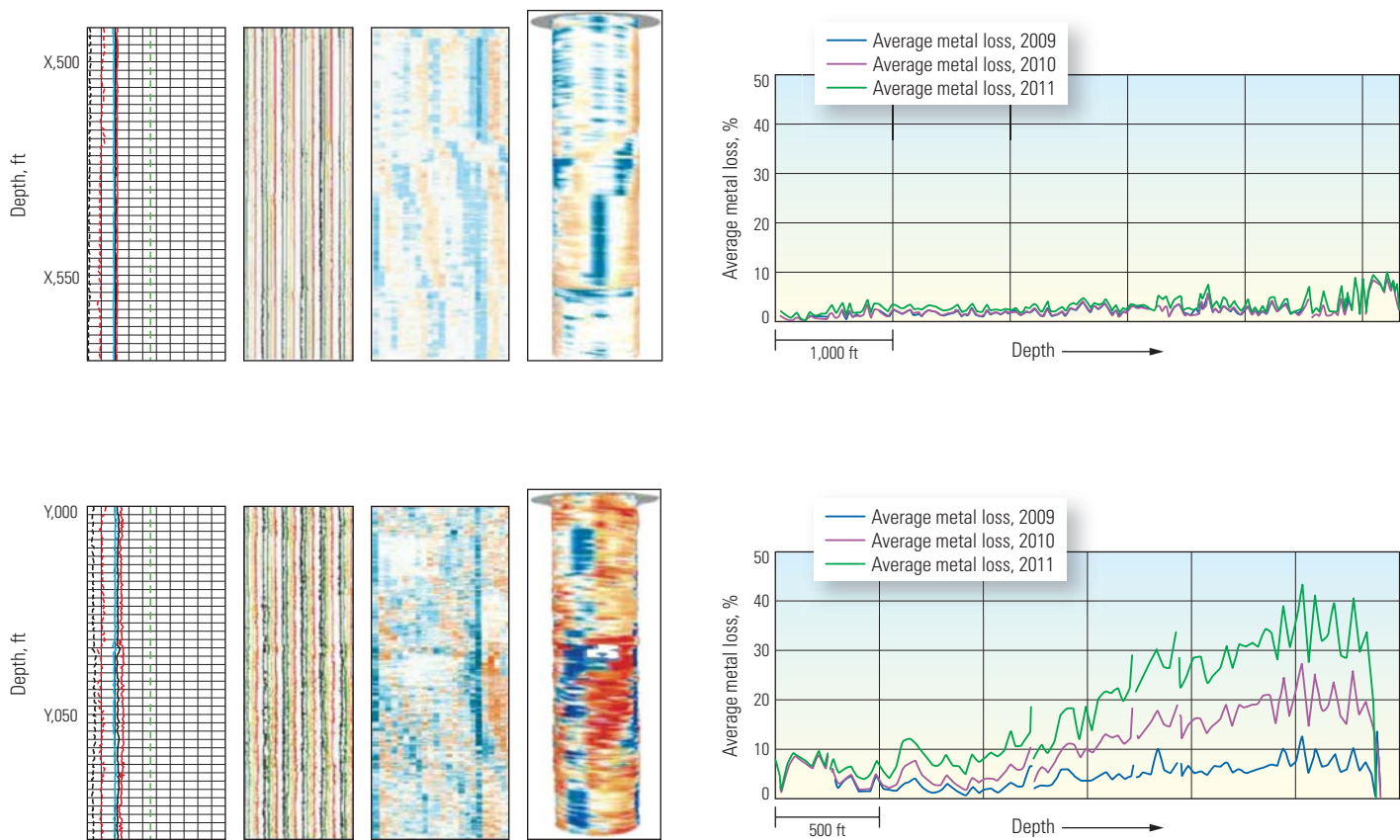
Abu Dhabi Company for Onshore Oil Operations (ADCO) deployed the PipeView tool to measure corrosion over time in a well within a mature and prolific field. The well was originally drilled in 1969 and has been worked over many times. During the most recent workover in 2006, a 7-in.



^ Multifinger caliper tools. Multifinger caliper tools measure the internal diameter in casings. Numerous calipers, or fingers, pressed against the wall of the pipe detect small changes in the pipe inner diameter that may be interpreted as wear or corrosion. In general, multifinger calipers come with varying numbers of fingers; a higher number of fingers is required for larger internal pipe diameters. The PipeView PS Platform new-generation production services multifinger imaging tool, the PMIT-24 fingers tool (left), requires mechanical centralizers (not shown). The PipeView PMIT-40 fingers tool (right) incorporates motorized centralizers. A third version, not shown, has 60 fingers.

19. Because the production fluids in these wells were known to be noncorrosive and the tubing-casing annulus contained diesel and corrosion inhibitor, any measured metal loss was assumed to be external only.

20. A cement squeeze is a remedial operation designed to force cement into leak paths in wellbore tubulars and casing strings. Squeeze cementing operations are performed to repair poor primary cement jobs, isolate perforations or repair damaged casings or liners.



▲ Corrosion logs obtained from a caliper tool. PipeView service data (*top left*) and average metal loss versus depth (*top right*) were recorded in 2009, 2010 and 2011 for the tubing across the point of gas injection. The logs in Track 1 (*top and bottom left*) include a measurement for nominal internal radius (dashed black line), nominal outer radius (dashed green line), eccentricity (dashed red line), minimum internal radius (solid blue line), maximum internal radius (solid red line) and average internal radius (solid black line) above and below the point of gas injection (*top and bottom left*, respectively). Track 2 is a trace of each caliper. Track 3 is an image log of thickness loss in the casing. Dark blue indicates the presence of scale, blue to white indicates 0% to 20% thickness loss, white to pink is 20% to 40% loss and orange to red indicates 40% to 80% loss. Pure red (not shown) would indicate 100% loss and a hole in the casing. The average metal loss above the point of gas injection (*top right*) did not change significantly during the three years, suggesting that the presence of the gas had a mitigating effect on corrosion. A similar plot for the tubing below the point of gas injection (*bottom right*) showed greater metal loss, which increased over the three-year period, suggesting more-aggressive corrosion.

tieback liner was run and cemented to the surface to cover a corroded section of 9½-in. casing. The operator then drilled a single 5½-in. horizontal well into a previously bypassed carbonate formation. This lateral was completed as a gas lift oil producer.²¹

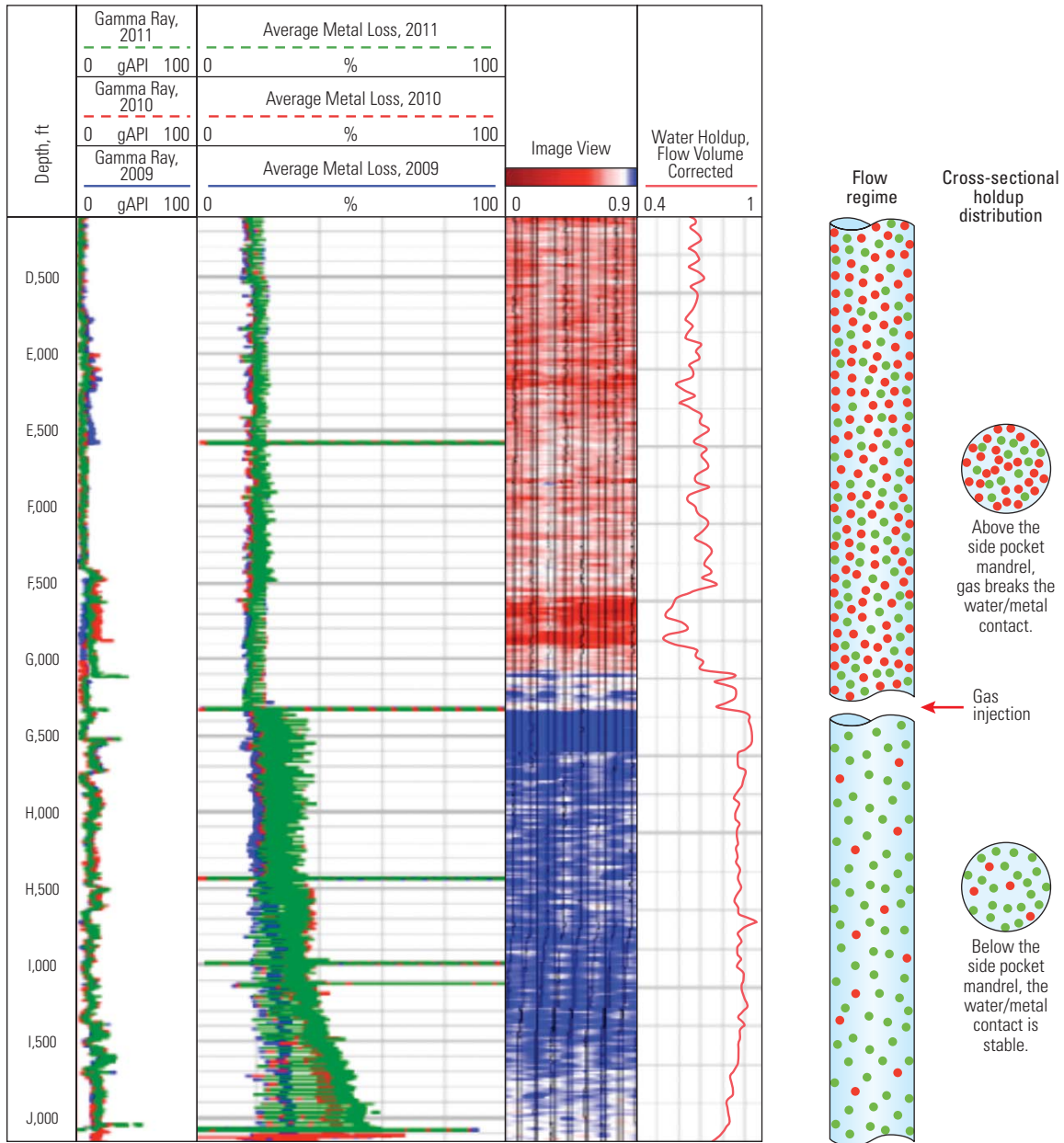
Company engineers used naturally produced gas with no corrosion inhibitor treatment as the injection gas, which entered the system through a gas lift side pocket mandrel. Concerned with the corrosion potential posed by the injection gas, ADCO engineers elected to run time-lapse monitoring surveys with the multifinger imaging tool to identify, quantify and track the growth of internal corrosion in the tubing and estimate a corrosion rate and time-to-failure. ADCO conducted surveys over a three-year period—2009 to 2011—using a 1½-in., 24-finger version of the tool.

The caliper logs revealed various degrees of corrosion in two sections of the tubing string, one below and one above the injection gas entry point at the side pocket mandrel (*above*). The lower section, from the bottom of the tubing up to the gas injection point, had experienced a significant degree of corrosion and subsequent metal loss that increased between 2009 and 2011. The upper interval, from the gas lift mandrel to the top of the tubing string, underwent minimal corrosion over the same period and retained its original manufacturing dimensions.

The operator postulated that the injection gas, which enters the produced oil-water flow at the mandrel and flows upward, provides an inhibitive effect on the production fluids. This effect reduces the corrosion rate in the upper interval, but because the produced fluids below the man-

drel did not contain lift gas, that section experienced a higher corrosion rate.

ADCO engineers are still speculating about the exact inhibitor mechanism; one plausible theory holds that the injected gas adds turbulence to the production flow and alters the flow regime, which reduces water holdup and water contact with the tubing's internal surface. This same phenomenon of less corrosion above the gas injection point has been observed in other gas lift wells in which caliper surveys were acquired. A caliper log in a similar well, in combination with a FloView holdup measurement, corroborates the theory that gas injection may be reducing water contact with the tubing (*next page*). The operator plans to use these results to refine the design of future gas lift well completions to take advantage of this effect.



^ Changes to the water holdup profile. A caliper log run in combination with the FloView water holdup probes in an ADCO well shows increasing corrosion over time (Track 2) below the point of gas injection and very little corrosion above the gas injection point. This phenomenon is attributed to a decrease in water holdup above the gas entry point. Analysts believe there is increased gas within the flow regime (*right*, red dots), which also includes significant water (blue) and oil (green dots). Water holdup, corrected for flowline volume (Track 4), is reduced in the upper section; the corrosion rate is less in the upper section than in the lower section, in which less gas is present. Water holdup is imaged (Track 3); blue represents water and red represents oil and gas.

Combining Measurements for Improved Corrosion Monitoring

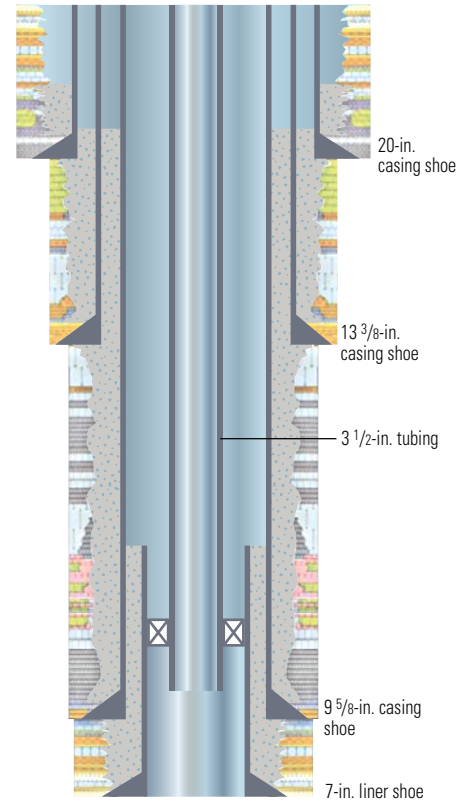
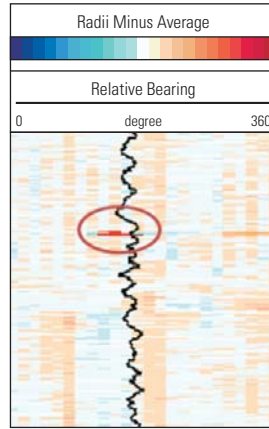
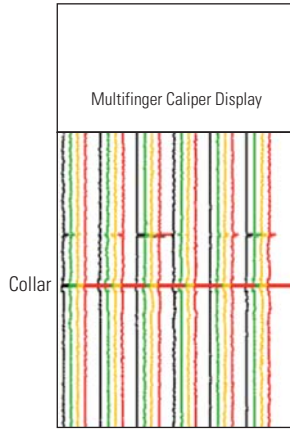
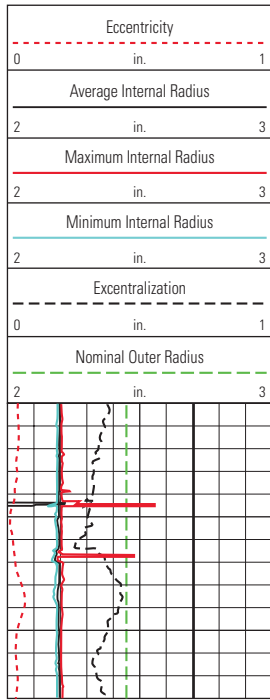
Operators may increase their understanding of the location and extent of downhole tubular corrosion by combining information from multiple tools. Kuwait Oil Company (KOC) did this for a well in an onshore field that includes wells that have been producing for more than 60 years.

Several factors, including the age, increased commingling of formation water production and the high CO₂ and H₂S content of the produced fluids, prompted KOC to examine the corrosion potential of these wells.

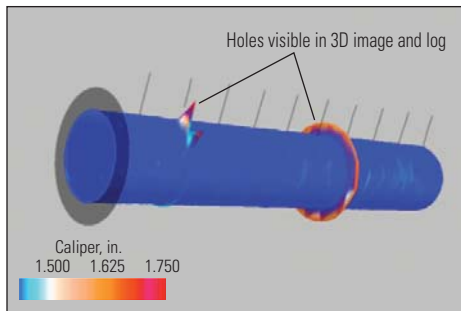
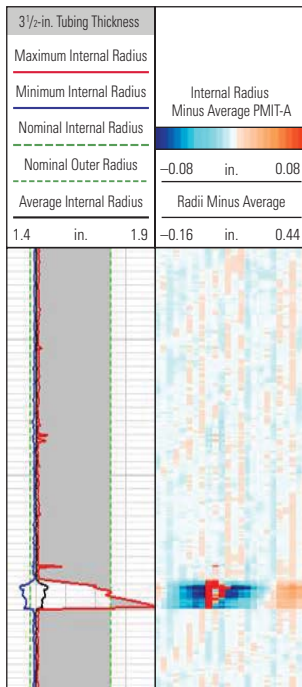
During a workover designed to perform a cement squeeze on existing perforations and recomplete the well—which had been drilled and

completed in September 2001 as a single producer—engineers discovered a leak in the wellbore. To locate the leak zone by quantifying the

21. Gas lift is an artificial lift completion method in which gas is injected into the production tubing to reduce the hydrostatic pressure of the fluid column in the well and the bottomhole pressure. This method allows reservoir liquids to enter the wellbore at a higher flow rate.



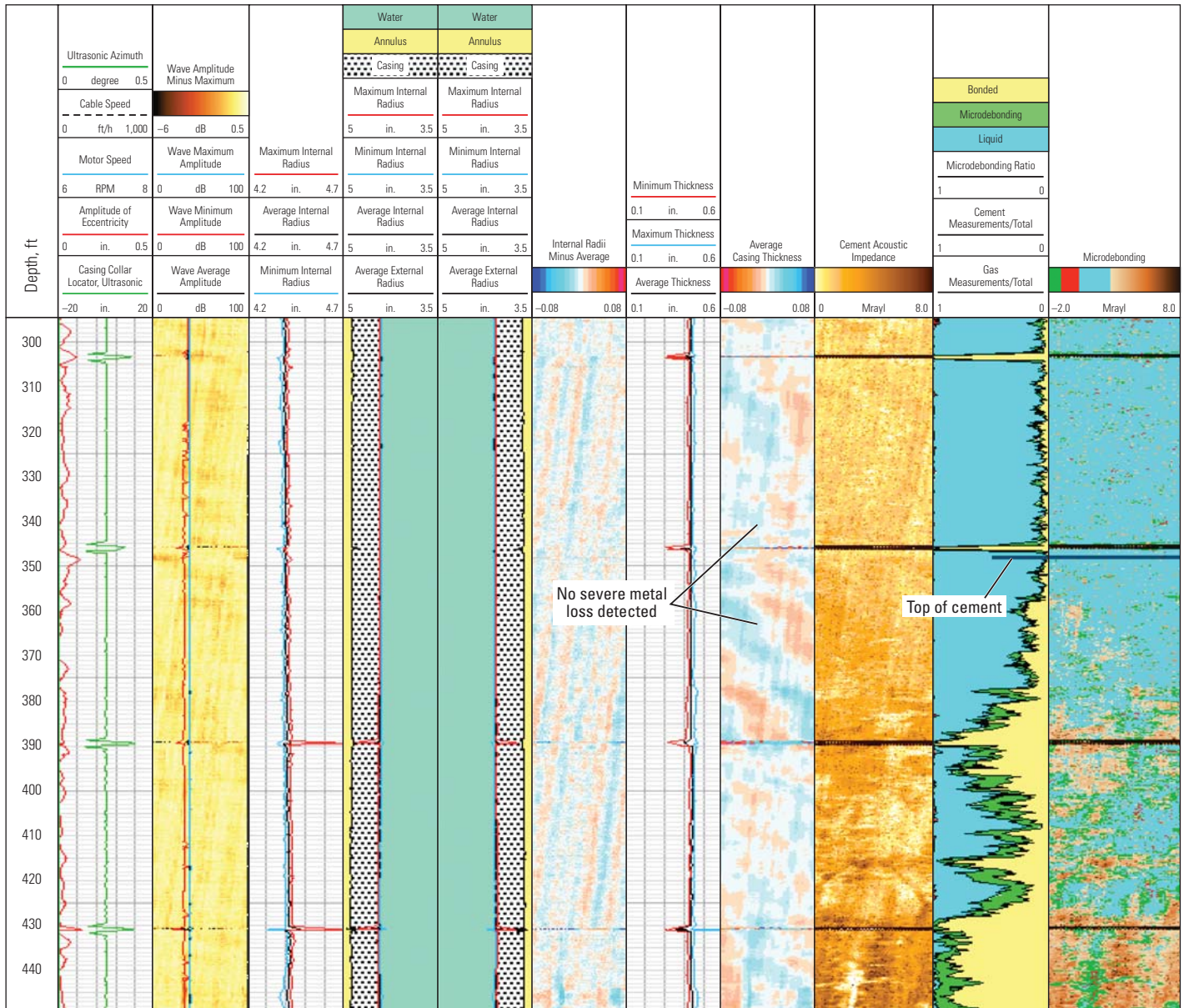
^ Casing program. The subject well in a field offshore Qatar contained 3 1/2-in. tubing, a 7-in. liner and concentric strings of 9 5/8-in., 13 3/8-in. and 20-in. casing.



^ Processed caliper log. The field logs from the PipeView multifinger caliper tool of the interval with 3 1/2-in. and 9 5/8-in. casing (top) correlated precisely with the visual damage observed in the retrieved tubing (bottom right). The caliper log (top left) includes measurements for eccentricity (dashed red line), average internal radius (solid black line), maximum internal radius (solid red line), minimum internal radius (solid blue line), excentralization (dashed black line) and nominal outer radius (dashed green line). The caliper log (top center) is composed of three traces that indicate casing collars used for depth correlation (horizontal red line). The image log (top right) in the casing indicates thickness losses. Dark blue indicates scale, blue to white indicates 0% to 20% metal loss, white to pink is 20% to 40% loss and orange to red indicates 40% to 80% loss. Red (circled) indicates 100% loss and a hole in the casing. A 3D processing image (bottom left) based on multifinger caliper data also indicates strong correlation with the damage observed in the retrieved tubing, as do the processed logs (bottom center).

1998, contained 9 5/8-in., 13-in. and 20-in. casing strings, a 7-in. liner and a 3 1/2-in. production tubing string (above). In 2011, the operator observed that the 13-in. casing had subsided at the well-head. A pressure test designed to check the integrity of each casing string demonstrated fluid flow in the annular space between the 9 5/8-in. and 13-in. strings and in the annular space separating the 13-in. and 20-in. strings. This indicated a leak in the 13-in. casing string.

Qatar Petroleum engineers implemented a workover operation, which they began by evaluating the integrity of the cement and presence of corrosion for the 7-in. liner and 9 5/8-in. casing. An ultrasonic inspection test identified the top of the cement behind the 9 5/8-in. casing and confirmed that the 7-in. liner and 9 5/8-in. casing were free from any significant corrosion or a hole in the casings that might allow fluids communication. Based on the location of the top of the cement, which was identified by the USI tool cement log, Qatar Petroleum engineers were able to determine the interval to cut for casing



^ Top of cement. Engineers used logs from the USI tool to accurately locate the top of the cement behind the 9%-in. casing (Tracks 10 and 11); standard USI tool data indicated that the 7-in. liner and the 9%-in. casing were free of significant corrosion.

retrieval (above). They could then directly evaluate the 13%-in. casing for corrosion defects.

Engineers next deployed the EM Pipe Scanner tool to evaluate the external casing strings. Despite the fact that measurements were made outside of the recommended specifications, the tool identified an anomaly at a depth above the seabed; the amplitude level across the anomaly was high, and the phase level was low, both of which suggested that less metal was present at the anomaly than would be expected under normal circumstances. This information reinforced the interpretation of the annular pressure test

data and pinpointed the precise location of the hole in the 13%-in. casing. A PipeView multi-finger imaging tool log was then run to evaluate the 13%-in. casing; the log showed that the casing was corroded and completely parted at the same depth where the EM Pipe Scanner tool had detected the metal loss (next page). These measurements provided Qatar Petroleum with a clear understanding of the location and extent of the corrosion damage such that company engineers could plan a strategy to retrieve the 13%-in. casing and perform a casing patch operation.

Qatar Petroleum had performed several workovers on another offshore well in the field and is using the well as a dump flooder, in which produced water is injected into another formation. Because the injected water is untreated, the production casing regularly experiences corrosion.

The well was originally cased with three sets of steel casing: a 20-in. surface casing, a 13%-in. intermediate casing and a 9%-in. production casing. After corrosion problems were detected in 2002, engineers overlapped the production casing with 7-in. casing. The well is perforated in one formation from 6,290 to 6,320 ft [1,918 to 1,926 m]

and in another from 6,523 to 7,030 ft [1,988 to 2,143 m]. Produced water from both formations is injected into a formation from 7,492 to 7,690 ft [2,284 to 2,344 m].

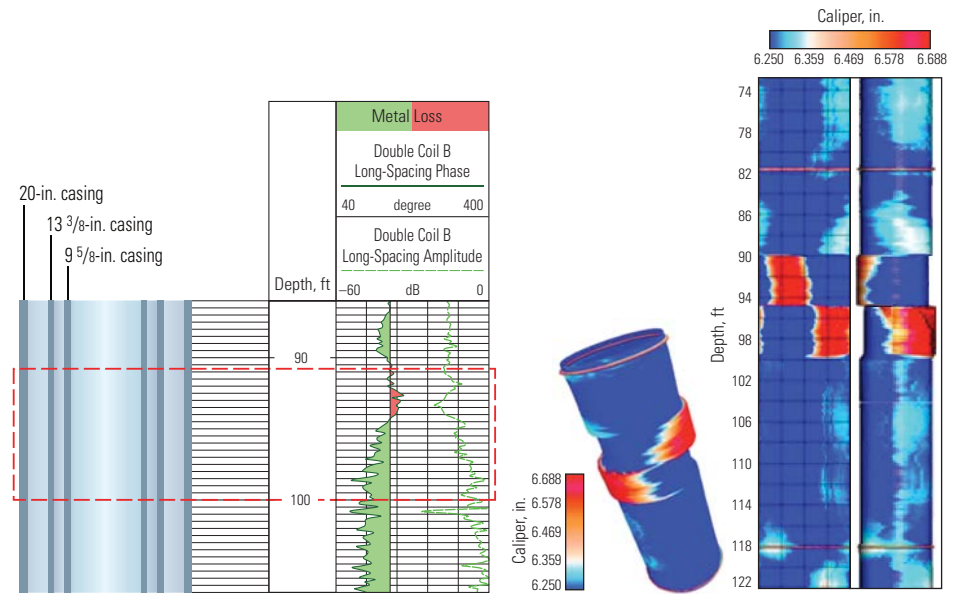
As part of regular operational monitoring and assessment of the well, Qatar Petroleum engineers deployed the EM Pipe Scanner tool to evaluate the well for corrosion. The tool's findings indicated significant metal loss across the 7-in. and the 9%-in. sections. At approximately 6,250 ft [1,900 m], the tool indicated a thickness of about 0.28 in. [0.71 cm], much less than the expected nominal thickness of 0.797 in. [2.03 cm], which implied a metal loss of approximately 65%. The well's history and the operator's local experience in the field suggested that the entire 9%-in. casing was completely corroded and the 7-in. casing was partially corroded with about 10% metal loss. The EM Pipe Scanner tool's high-frequency image measurement confirmed that the 7-in. inner casing was not fully penetrated by corrosion, which indicated that the inside wall of the pipe was in good condition.

Improved Corrosion Mitigation Through Management

Downhole corrosion monitoring tools help engineers understand the physical condition of tubing and casing strings. Operators can then make more-informed and cost-effective mitigation and repair decisions. But as companies continue to search for more streamlined and holistic methods for protecting their assets and extending the producing life of their wells, service providers have worked to improve monitoring capabilities.

For example, the advent of online, near real-time measurement capabilities has brought about a natural progression to developing corrosion monitoring workflows and software platforms that maximize the usefulness of recorded data. These platforms use advances in information and communication technology to improve oil and gas E&P efforts with the objectives of optimizing field operations and avoiding nonproductive time.

Schlumberger engineers are working to integrate corrosion measurement data gathering into overall field operations. These efforts are focused in three software-based management platforms. The Petrel E&P software platform provides operators and service companies with a reservoir-level view of field optimization by allowing asset teams to build collaborative workflows based on geomechanical, geochemical and reservoir fluid properties. Along with information such as the reservoir temperature and pressure and the expected corrosive characteristics of production



▲ Significant metal loss. Even though the EM Pipe Scanner tool was run outside of its specified range for amplitude and phase, it detected significant metal loss across the three casing strings (dashed red box, top left). The 3D (top center) and 2D (top right) visualizations produced from the PipeView multifinger caliper tool log run in the 13%-in. casing indicate the casing had corroded to the point that it had parted (bottom left and right) at the depth where the EM Pipe Scanner tool had detected metal loss.

fluids in the reservoir, the Petrel software helps guide well planners in making well decisions to ensure a high-integrity wellbore constructed of appropriate alloys.

The Techlog wellbore software platform further advances this evaluation by providing wellbore-centered workflows to identify corrosion risks. These workflows incorporate fluid composition and flow rate data to flag any potential corrosion-induced wellbore problems, allowing the operator to make construction and completion decisions that minimize corrosion's impact. The Avocet production operations software platform combines well operations and production data management systems to deliver a clear and comprehensive picture of operations at the surface. The Avocet software accepts corrosion

data recorded from various monitoring techniques and analyzes such data for their impact on production. The software flags those areas with higher corrosion rates or a history of corrosion-related events, and as a result, the operator can prioritize corrosion mitigation efforts and implement suitable preventive measures.

As the industry moves into more-aggressive corrosion environments and technically demanding production regions, corrosion monitoring advances such as these must continue to expand and evolve if operators are to remain both profitable and environmentally responsible. — TM