

The Expanding Role of Mud Logging

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1. Like electric logs, most mud logs conform to format standards set forth by the Society of Professional Well Log Analysts (SPWLA). For mud log standards promulgated by SPWLA: Mercer RF and McAdams JB: "Standards for Hydrocarbon Well Logging," *Transactions of the SPWLA 23rd Annual Logging Symposium*, Corpus Christi, Texas, USA, July 6–9, 1982, paper LL.

For decades, samples and measurements obtained at the surface have provided mud loggers with insights into conditions at the bit face. Information captured through mud logging gave operators early indications of reservoir potential and even warned of impending formation pressure problems. New sampling and analysis techniques, along with advances in surface sensor design and monitoring, are bringing the science of mud logging into the 21st century.

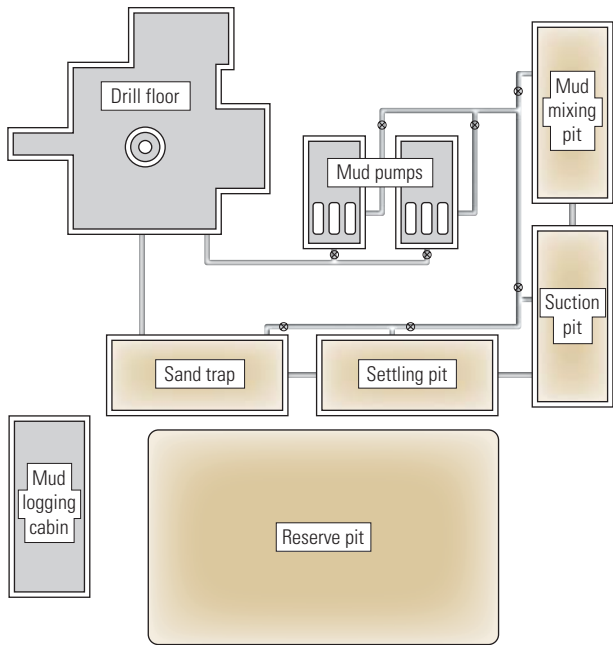
The mud logging unit has long been a common wellsite fixture. First introduced commercially in 1939, these mobile laboratories carried little more than a coffee pot, a microscope for examining formation cuttings and a hotwire sensor for detecting the amount of hydrocarbon gas encountered while drilling. The mud logger's job was to record the depth and describe the lithology of formations that the drill bit encountered, then determine whether those formations contained any oil or gas.

Outside the logging unit, the mud logger's domain ranged from the shale shaker to the drill floor. The shale shaker yielded formation cuttings and gas—both liberated by the drill bit—which were transported to the surface in the drilling fluid. Periodic visits to the shaker permitted the mud logger to collect cuttings for microscopic examination, while a suction line between the shaker and the logging unit carried gas from the gas trap to the logging unit's hotwire gas detection system. Visits to the drill floor allowed important exchanges of information between the mud logger and driller. Using basic surface measurements, the mud logger was able to produce a concise account of drilling activity.

For decades, gas measurements, lithology and rate of penetration (ROP) provided the earliest indications of reservoir potential. Before the advent of measurements while drilling (MWD) and logging while drilling (LWD), mud loggers were able to obtain valuable formation data from wells in which drilling conditions, formation characteristics or well trajectory conspired

against deployment of wireline logging tools. In such wells, analysis of mud gas and cuttings often provided the first, and perhaps only, indication that a formation might be productive. Today, although LWD technology is able to give the first glimpses of near-bit conditions in real time, adverse wellbore conditions sometimes preclude the use of downhole logging tools. In such cases, the mud log continues to inform operators of the producibility of their wells. At a minimum, the mud log gives the operator an early indication of zones that merit special attention, additional logging services or production tests.

The mud log serves a variety of functions. As a correlation tool, the mud log's ROP and total gas curves exhibit a remarkable correspondence to gamma ray and resistivity curves, respectively.¹ Throughout the drilling process, mud logs provide real-time correlations with logs from neighboring wells and help the operator track the bit's position in relation to target formations. Because the mud log is based on physical samples, it provides direct, positive identification of lithology and hydrocarbon content. This information can be helpful when formation characteristics make wireline or LWD log interpretation complicated or ambiguous. It can also fill gaps where other such measurements have not been obtained. Thus, when integrated with wireline or LWD measurements, cores and well test data, the mud log provides independent evidence for a more comprehensive understanding of reservoir conditions and geology.



Bit Depth	5507.5 ft	TVD Depth	5506.5 ft
Tot Depth	5507.5 ft	LAG Depth	5423.4 ft
HK Hght	19.8 ft	ROP ins h	97.16 ft/h
WOH	175.6 klbs	Sum 1 h	437.6 bbl
WOB	33.3 klbs	FLW OUT h	39.42 %
RPM	94 rpm	Pump 1	69 spm
TORQUE	5239 lb*f	Pump 2 h	71 spm
FLWpmps	493.64 qpm	Vol +/-	-7.1 bbl
SPP 1	1425 psi	STD Cntrh	75 nbs
TVD Depth	5506.5 ftm	LAGtim	55.2 min
Pit 1	103.66 bbl	PT GAS ma	16 Unit
Pit 2	134.53 bbl	C1 main	2783 ppm
Pit 3	144.0 bbl	C2 main	31 ppm
Slug Pti	51.4 bbl	C3 main	0 ppm
TTK	4.0 bbl	iC4 main	13 ppm
PVT	386.2 bbl	nC4 main	0 ppm
TMP IN	90.4 deg	MW IN	9.8 ppq
TMP OUT	69.1 deg	MW OUT	9.8 ppq

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The scope of the basic mud logging service has broadened over time, as additional sensors brought more data into the logging unit—expanding in diversity from gas chromatographs to weight-on-bit and mud pit level indicators. The mud logging service now typically tracks ROP, lithology, visual hydrocarbon indicators, total combustible gas in mud and individual hydrocarbon compounds in the gas, along with numerous drilling parameters. As a hub for monitoring drilling operations and rig sensors, the mud logging unit has become a source of crucial information for the company representative, the driller and the geologist.

The mud logger's role takes on added importance when there is a *drilling break*, or significant increase in ROP. Then the mud logger alerts the company representative and requests that drilling be stopped until mud and cuttings from the bit face can be circulated to the surface. If mud analysis indicates the presence of hydrocarbons—called a *show*—the mud logger informs the geologist, who may elect to core or test the interval. Geochemists and biostratigraphers also rely on mud loggers to collect representative samples needed to make correlations and develop geologic models.

From a drilling standpoint, the mud logger's most important task is gas monitoring. Mud gas trends that develop while drilling are integral to evaluation of mud balance and identification of potentially overpressured formations. By carefully tracking gas and drilling parameters, the mud logger can recognize impending deviations from normal trends and give advance warning so the driller and company representative can mitigate the problem by adjusting the density of the drilling fluid or shutting in the well. Thus, the success of a well and the safety of the drilling operation may hinge on how quickly a mud logger can synthesize and interpret myriad pieces of data.

Mud logging capabilities have evolved over the years. By the mid-1950s, gas samples were being analyzed by wellsite gas chromatography. In the 1960s, mud logging companies began offering geopressure detection services.² Automated event recorders, made possible through use of robust microelectronic components, were incorporated into mud logging processes during the 1970s. During the following decade, mud logging units entered the computer age. Computers took the burden of printing the log away from the mud logger, who used to laboriously compile the data and then draw the log by hand. In addition, computers allowed mud loggers to organize and track data from multiple sources without sensory overload.

Advances in computing and networking technology, surface sensor design and sample analysis are bringing the mud logging unit into the 21st century. Today, even more sensors lead into the logging unit, each acquiring data at a frequency of several times per second. To handle this increase in data volume, a context-aware processing system—based on computer-generated trend lines and a library of established models—makes the data easier for the mud logger and other end users to comprehend. Digital images of samples viewed under the microscope can be rapidly transmitted from the wellsite to the client office. And new approaches to gas sampling and analysis have been developed to extract geochemical properties at the wellsite.

This article describes how a basic mud log is assembled, reviews sampling and analysis techniques used in formation evaluation and discusses basic methods for monitoring pressure. An overview of recent sensor technology maps the evolutionary path from basic formation evaluation to advanced analysis of mud gases for geologists and well integrity services for drillers.

Mechanics of Mud Logging

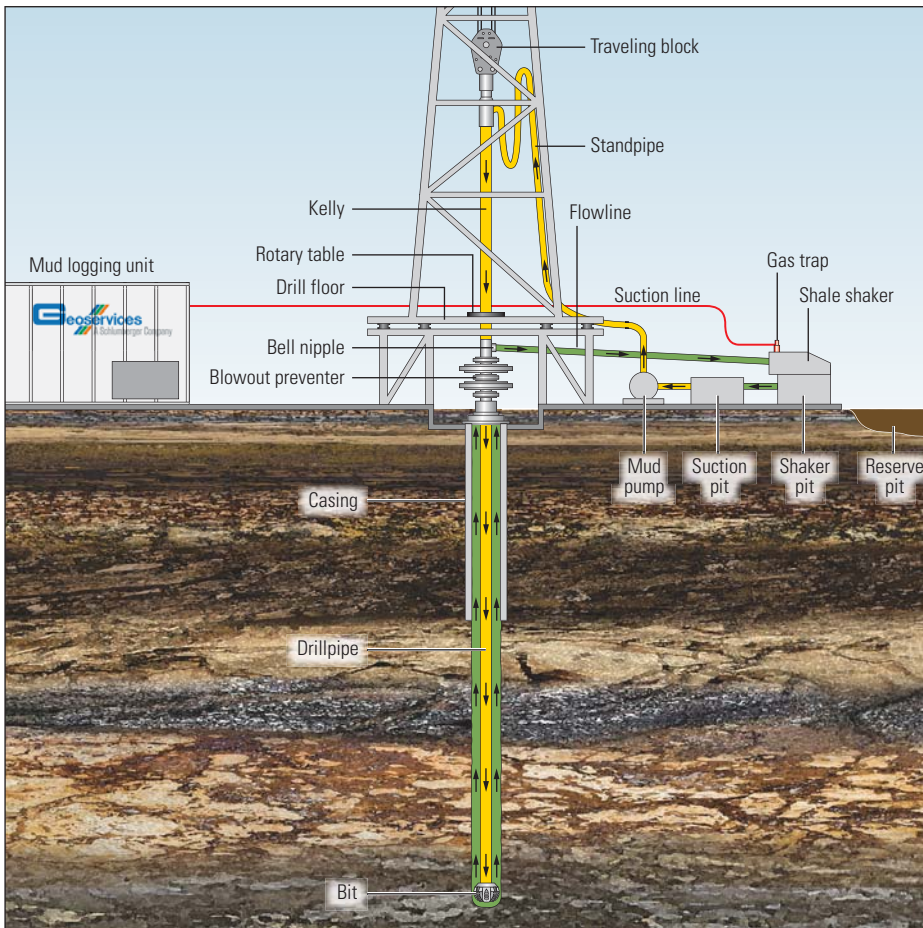
In the oil field, drilling fluid is integral to every drilling project. Be it water-base, oil-base or gas-base, drilling fluid is vital to the process of making hole:

- It streams under pressure through jet nozzles on the drill bit to clean the bit and carry heat away from the bit face.
- It transports drill cuttings from the bit face to the surface, thus playing an essential role in the hole cleaning process.
- It offsets bottomhole pressure to help maintain wellbore stability and prevent the influx of formation fluids that could cause blowouts.

Over time, numerous variations on the basic mixture of clay- and freshwater-base drilling fluids have been developed (and sometimes discarded). Well-known variations are based on saltwater, mineral oil, diesel oil, polymers, nitrogen, mist and foam. Each type has specific properties that deliver superior performance in certain drilling environments. And each requires special accommodations when it comes to mud logging: Some require custom sampling techniques; others require special sample rinsing procedures. This section focuses on the simplest of environments, in which freshwater-base drilling muds are used.

The practice of mud logging relies heavily on the mud circulation system, which carries formation cuttings and fluids to the surface. High-pressure mud pumps draw drilling fluid from surface tanks and direct it downhole through the drillpipe (left). The mud exits the drillstring through nozzles at the face of the bit. Pump pressure forces the mud upward through the annular space between the drillpipe and casing, to exit at the surface through a flowline above the blowout preventer. The mud then passes over a vibrating mesh screen at the shale shaker, where formation cuttings are separated from the liquid mud. The mud falls through the screens to the mud pits. The mud falls through the screens to the mud pits before being pumped back into the well.

As a bit drills through the subsurface, the rock it grinds up—along with any water, oil or gas contained therein—is carried to the surface by the drilling mud. What arrives at the surface and when it arrives



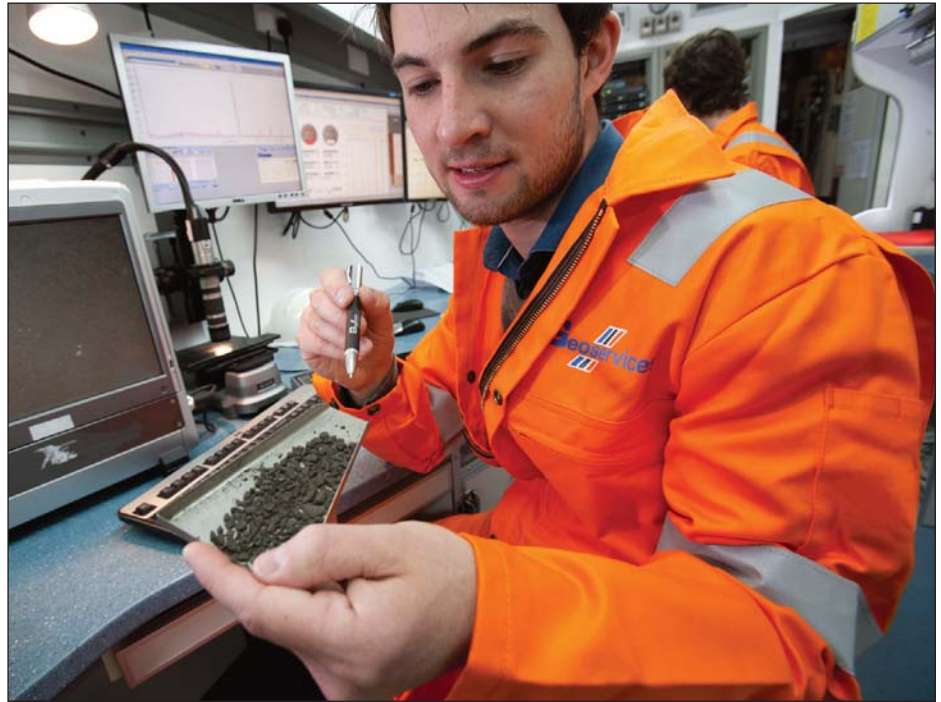
▲ Mud circulation system. Drilling mud, drawn from the suction pit and pumped through surface pipe, is sent downhole through the center of the drillpipe. It enters the open borehole through nozzles (not shown) on the bit. The mud cools and lubricates the bit, then carries away formation cuttings and fluids as it moves upward in the annular space between the pipe and borehole wall. At the surface, the mud, formation fluids and cuttings are diverted through a side outlet in the bell nipple and through an inclined flowline to the shale shaker. A mud agitator, or gas trap, is positioned at the shaker's header box to liberate gas from the mud. A suction line at the top of the agitator siphons gas off from the mud and sends it to the mud logging unit for analysis. The mud flows over the shaker, where screens separate the cuttings from the mud, which is returned to the shaker pit.

are fundamental to the science of mud logging. The type of material and the timing of its arrival are influenced to varying degrees by drilling practices, lithology and pressure.

The mud logger requires samples of formation cuttings to ascertain the subsurface geology at a given depth. Therefore, cuttings must be large enough to trap on the shaker or desilter screens. On average, rock cuttings are roughly the size of coffee grounds (right). Their size is controlled largely by how consolidated the rock is, along with grain size and cementation of the rock. In shale, pressure can affect the size of cuttings, and large elongated cavings of spalling shale that pop off the borehole wall are a strong indicator of overpressure. Bit type plays a significant role as well. Roller cone bits with chisel teeth produce a coarser grade of cuttings than do those with carbide buttons. Polycrystalline diamond compact (PDC) bits in soft formations typically use large cutters that produce large cuttings (below right). Harder formations call for smaller PDC cutters, which produce smaller cuttings.

The volume of cuttings that flow across the shaker is a function of bit size and ROP.³ Bit size controls the cross-sectional area of the hole. ROP controls the thickness of the interval drilled over a given period. These factors are, in turn, affected by pump rate, weight on bit (WOB), rotary speed, fluid viscosity and mud density, commonly referred to as mud weight (MW).

To characterize the lithology of a particular interval in a well, the mud logger must account for the transport velocity of the cuttings to correctly determine the amount of time it takes the cuttings to travel from the bit face to the shale shaker. This lag time increases with depth, taking just a few minutes while drilling the upper section of a well, but extending to several hours in deeper sections. An accurate determination of lag time is crucial for precisely correlating cut-



^ Cuttings sample. Having been cleaned and dried, these shale cuttings will be examined under a microscope.

tings and fluid samples to the formations and depths from which they originate.

One method for determining lag is to calculate the amount of time required to displace the total annular volume of drilling fluid. This method calls for the mud logger to factor in the length and diameter of the open hole, the capacity and displacement of the tubulars—riser, casing and drillpipe—in addition to mud pump output, with separate calculations performed at each change in hole or pipe diameter. However, the calculated result tends to be optimistic, underestimating hole volume because it does not account for rugosity or washouts, which affect mud volume and velocity of flow.

A more reliable method for determining lag time may be obtained through use of a tracer that is pumped downhole and detected upon its return to the surface. Various tracer substances have been tested, ranging from oats, corn or rice to paint, calcium carbide nuggets or injected gas—some types are precluded out of concern for their effects on downhole equipment; others are used only in certain regions.⁴ In most cases, the tracer is simply wrapped in tissue paper, then inserted into the drillpipe when a connection is made on the drill floor. The paper disaggregates on its trip through the drillpipe and the tracer passes through the nozzles in the bit. The mud logger starts a timer when the pumps are turned on, and the time it takes the tracer to circulate downhole

and back to the surface is calculated so that the mud logger can anticipate its arrival. The timer is turned off when the tracer reaches the shale shaker. Knowing the pump rate and the inside diameter of the drillpipe, the mud logger can calculate the fluid volume contained within the pipe to TD; then, knowing the pump displacement, the number of strokes to pump the tracer downhole can be calculated. The mud logger can convert this to the time it takes the tracer to travel from the surface to the bit. Subtracting this time from the total measured time allows computation of the lag time from the drill bit to the surface.

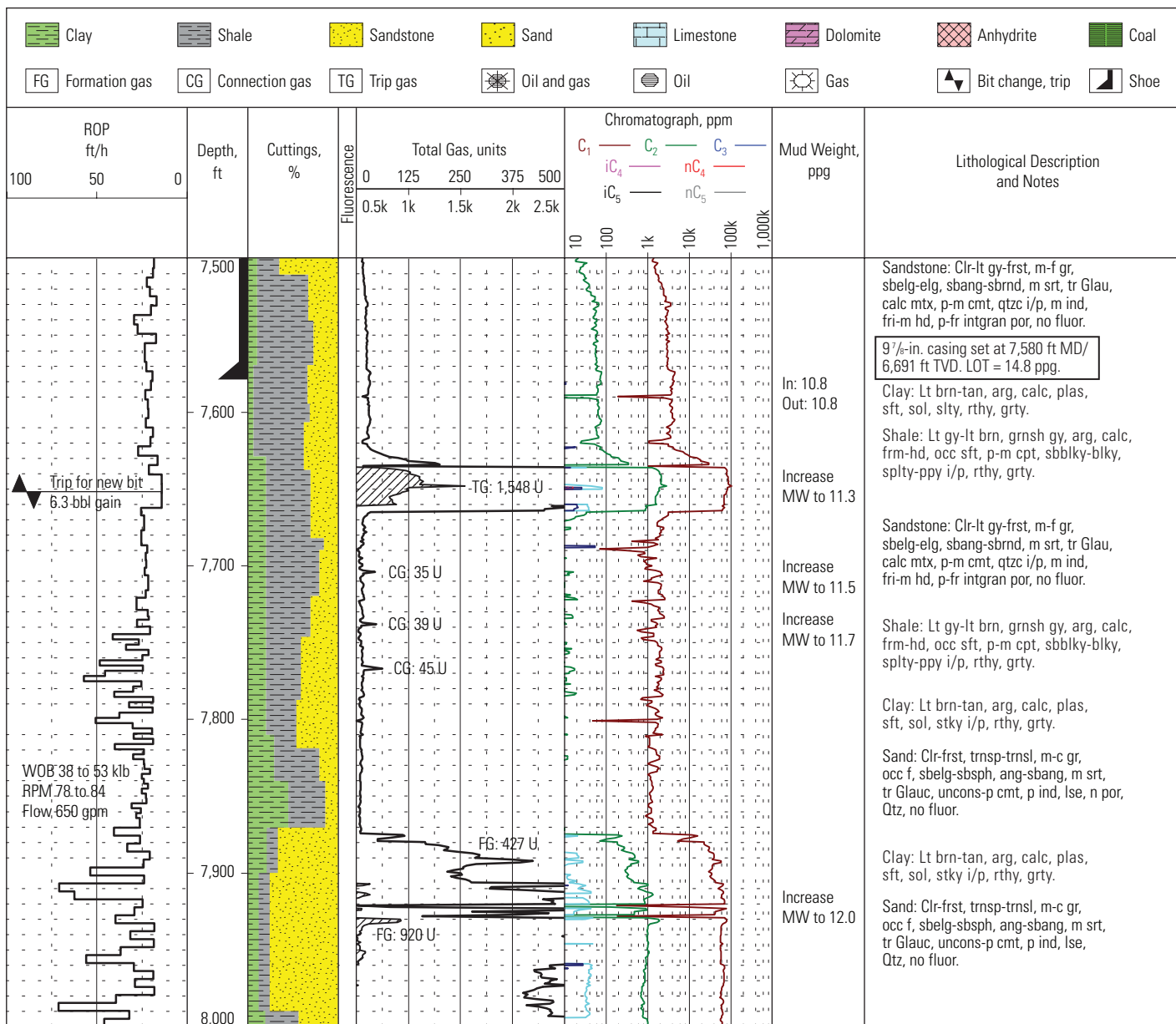


^ Cuttings from a PDC bit. Claystone in a mud logger's sieve shows tool marks, evidence of shearing action by a PDC bit.

2. Geopressure is synonymous with formation pressure. In common oilfield parlance, the term refers to an anomalous fluid pressure condition that is above or below the normal hydrostatic pressure condition for a given depth. Normal pressure, overpressure or underpressure is either equal to, above or below hydrostatic pressure, respectively. For more on this topic: Barriol Y, Glaser KS, Pop J, Bartman B, Corbiell R, Eriksen KO, Laastad H, Laidlaw J, Manin Y, Morrison K, Sayers CM, Terrazas Romero M and Volokitin Y. "The Pressures of Drilling and Production," *Oilfield Review* 17, no. 3 (Autumn 2005): 22–41.

3. Whittaker A: *Mud Logging Handbook*. Englewood Cliffs, New Jersey, USA: Prentice Hall, 1991.

4. Calcium carbide [CaC₂] reacts with water in the drilling fluid [CaC₂+2H₂O→C₂H₂+Ca(OH)₂]. The acetylene [C₂H₂] produced in this reaction is a gas not normally found in sediments. The acetylene will, in turn, be picked up at the gas trap, and its arrival will be noted automatically by the gas detector and gas chromatograph inside the mud logging unit.



▲ Excerpt from a basic mud log. A mud log typically displays ROP, depth, cuttings lithology, gas measurements and cuttings descriptions. It may also contain notes on mud rheology or drilling parameters. This log documents fairly routine drilling, with casing set in a shaly interval at 7,580 ft. After drilling out of casing and running a leakoff test (LOT), ROP was about 25 to 30 ft/h [7.6 to 9 m/h]. A trip for a new bit at 7,650 ft resulted in 1,548 units of trip gas (TG). During drilling at near-balanced conditions, small increases in connection gas (CG) were observed following each connection, prompting the driller to raise the mud weight. An increase in ROP at 7,890 ft signified a drilling break, which was accompanied by increasing sand content and a gas show, which reached a peak of 920 units of gas (FG). Gas detector results are expressed in parts per million (ppm) of equivalent methane in air on a volume basis, where 10,000 ppm is equal to 1% methane, or 50 units. The wellsite gas chromatograph typically tracks methane [CH₄]—denoted as C₁—as well as the following constituents: ethane [C₂H₆] or C₂, propane [C₃H₈] or C₃ propane [C₃H₈] or C₃ and the normal isopolymers of butane [C₄H₁₀] or nC₄ and iC₄ and pentane [C₅H₁₂] or nC₅ and iC₅.

Lag can also be measured in mud pump strokes. Sensors placed on the mud pumps detect piston movement and transmit a signal to the pump stroke counter display in the mud logging unit. The counters are set to zero when the tracer is inserted into the drillpipe and are read when the tracer arrives at the surface. A pump stroke counter will add increments only when the pump is running; its rate thus reflects the true pumping rate, despite interruptions for connections or pump maintenance. The number of pump strokes

needed to pump the tracer downhole to the bit is subtracted from the total count to determine the number of pump strokes required to circulate the mud and cuttings from the drill bit to the surface.

Lag is usually measured on a daily basis and at each casing point. The calculated lag is useful in determining the impact of formation washouts between measured lag intervals. For example, a carbide tracer is placed into the drillpipe during a connection. After 1,800 pump strokes, the gas detectors record an acetylene peak. Given that the

calculated lag was 1,710 pump strokes, this 6% difference in lag time can be attributed to borehole

5. ECD is the effective density exerted at a given depth by circulating fluid against the formation. The ECD is calculated as:

$$ECD = d + P / (0.052 \times D),$$

where d is the mud weight in pounds per gallon (lbm/galUS); P is the pressure drop in psi in the annulus between depth, D , and surface; D is the true vertical depth in ft and 0.052 is the conversion factor from psi/ft to lbm/galUS.

6. In this case, swabbing refers to a slight reduction in annular pressure caused by pipe movement during a connection. The amount of gas produced into the borehole as a result of swabbing depends on mud rheology, pipe velocity during movement and pipe and annulus diameter.

enlargement. By multiplying pump displacement by the difference in pump strokes, it is possible to determine the total volume of borehole washouts. This volume is also used in extrapolating lag calculations beyond the measured lag point.

In some cases, another type of gas may help mud loggers keep track of lag. Connection gas is typically detected when drilling at near-balanced conditions in which pressure exerted by the mud is held close to formation pressure. When a connection is made on the drill floor, the mud pumps are stopped and the pipe is picked up to bring the bit off bottom. With pumps off, the effective mud weight is reduced from equivalent circulating density (ECD) to static mud weight, and the hole is swabbed somewhat as the pipe is picked up.⁵ These conditions can create a reduction in bottomhole hydrostatic pressure sufficient for small amounts of gas to be produced by the formation.⁶ When present, this connection gas is detected at one lag interval after a pipe connection. Each occurrence of connection gas reflects the amount of lag for the depth of the bit when the connection took place.

Basic Formation Evaluation

In its most basic form, the mud log is a record of the drill rate, cuttings lithology, total combustible gas and individual hydrocarbon compounds brought to the surface during drilling operations.

The mud log provides a condensed record of subsurface geology, the hydrocarbons encountered and notable activities while drilling the well (previous page).

The ROP curve records how much time the bit takes to penetrate each meter or foot, as determined by a sensor on the drawworks. The ROP curve can be plotted as a step chart or a continuous line, increasing from right to left. When displayed in this manner, the ROP curve responds to changes in rock type or porosity in much the same manner as a spontaneous potential or gamma ray curve, making for easy correlation between these curves.

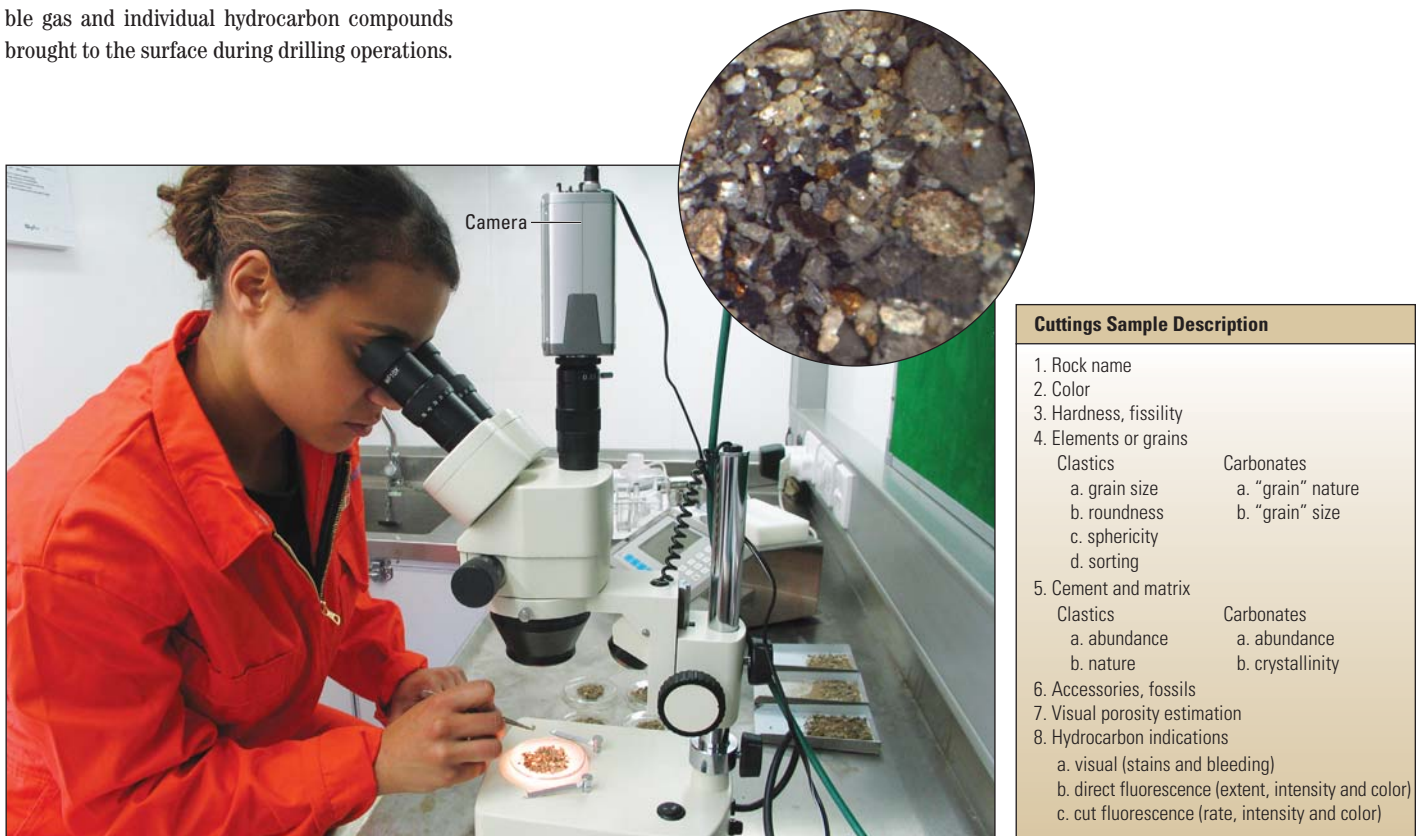
A variety of factors affect ROP, including rock type, porosity, WOB, MW and rotary speed (rpm) as well as bit type, diameter and condition. Because drilling practices affect ROP as much as geology does, the mud logger makes note of certain drilling parameters next to the ROP curve, especially when they change.

The ROP curve is interpreted in the same manner as a gamma ray log. Typically, a shale baseline is established through a thick interval of generally slow, consistent drilling—the shale inference can be verified through analysis of

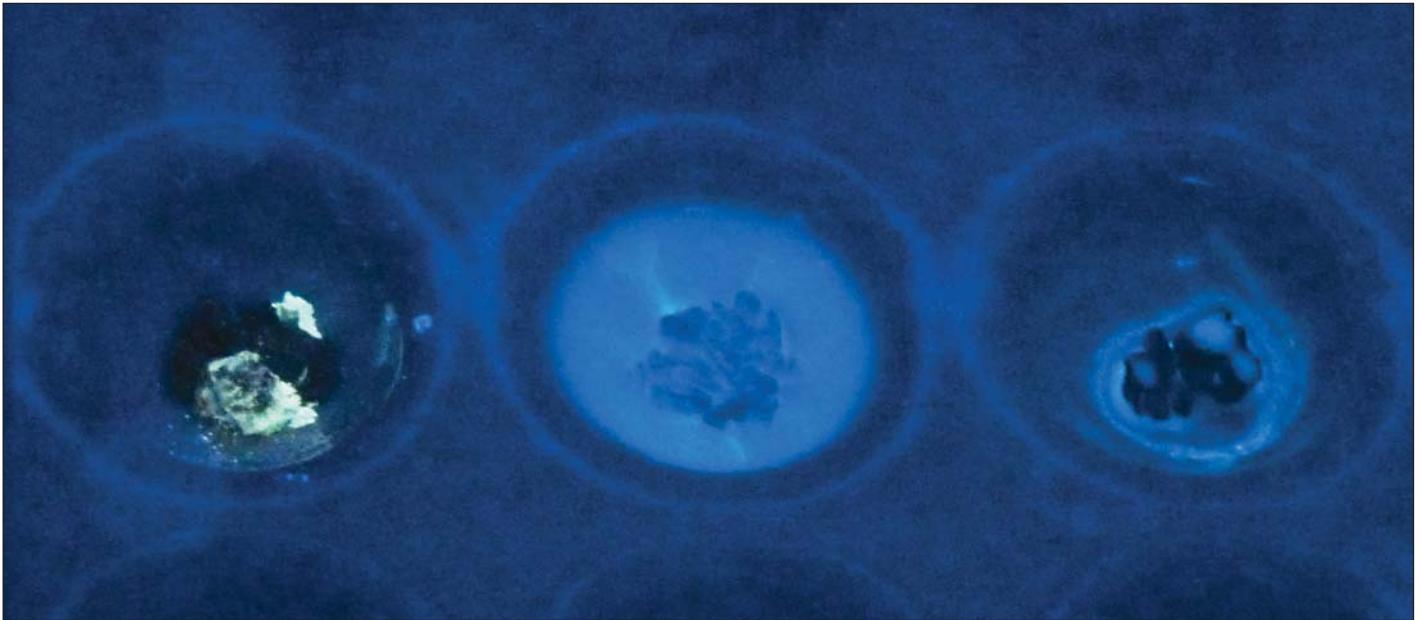
formation cuttings. Deviations from this ROP baseline may indicate a change in lithology or other downhole variables. For example, a drilling break may signify a change from shale to sand or an increase in bottomhole pressure caused by crossing a fault. A sudden decrease in ROP, sometimes called a *reverse drilling break*, may indicate a transition to rock of greater density, or it may signal a problem with the bit. These indicators must be weighed against other measurements to ascertain their true cause.

The lithology column is based on analysis of lagged samples of cuttings. Samples are generally collected at regular intervals—for example, every 3 m [10 ft] or every 10 m [30 ft]—and prior to tripping out of the hole. They are also collected when ROP or gas curves exhibit significant deviations from established trends, indicating changes in formation characteristics. The lithology column displays an estimate of gross lithology as a percentage of cuttings, reported in 10% increments.

The cuttings sample is rinsed and dried, then examined under a binocular microscope. The sample is then described in terms of lithology, color, grain size, shape, sorting, porosity, texture and other characteristics relevant to the particular rock type (below).



^ Microscopic examination. Rinsed and dried samples are examined under a microscope (left) to provide lithological descriptions (right) for the mud log. The inset photograph shows a typical sample with a mix of rock types, dominated by gray claystone with a lesser fraction of clear to off-white sand. In some logging units, a camera is attached to the microscope. This allows the mud logger to thoroughly document potentially productive zones, uncommon minerals, distinctive marker beds or even metal shavings (indicative of casing or bit wear) found in the sample.



^ Fluorescence under UV light. Mineral fluorescence (light colors, *left*), often seen in rock samples, is not an indicator of pay. Streaming cut (*center*), however, is produced by an oil-bearing sample placed in solvent. Two faint streams of oil can be seen at the 5 o'clock and 11 o'clock positions on the sample. As this milky cut streams oil into the solvent, it gives the clear solvent a light blue hue. After the solvent is allowed to dry, any oil residue will produce a fluorescent ring on the sample glass (*right*), which is useful for detecting oil in low-permeability samples that do not readily produce streaming cut. (Photograph courtesy of G. Haines.)

The presence of hydrocarbons may not be obvious—even under a microscope—so each sample is subjected to a variety of simple tests to screen for hydrocarbons. First, the sample is examined under an ultraviolet (UV) light. Fluorescence is an extremely sensitive test for the presence of hydrocarbons in mud, drill cuttings and cores. Sample fluorescence is evaluated in terms of color (ranging from brown to

green, gold, blue, yellow or white), intensity and distribution. Fluorescence color can indicate oil gravity, with dark colors suggestive of low-API gravity, heavy oils, while light colors indicate high-API gravity, light oils.

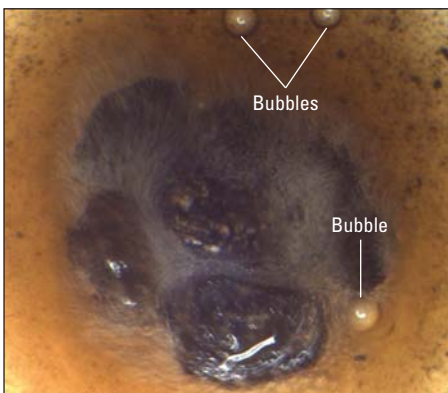
Because fluorescence may be attributed to a number of causes, the cuttings that fluoresce are separated from the main sample for further examination. Various mud additives, oil in the rock and certain types of minerals—such as pyrite and calcite—may cause a sample to fluoresce. The mud logger must compare mud additives against rock cuttings to recognize the effects of additives. Mineral fluorescence may closely resemble oil fluorescence, but the difference can be confirmed by application of a solvent. Mineral fluorescence will remain undisturbed, whereas hydrocarbon fluorescence will appear to flow and diffuse into the solvent as the oil dissolves. This diffusion is known as *cut fluorescence*, or more commonly just *cut*. Under UV light, hydrocarbons may be seen to stream from the rock pores into the surrounding solvent, turning the solvent cloudy. If no streaming cut is observed, the sample is left until the solvent has evaporated and then examined once more under UV light. A fluorescent ring around the sample indicates that hydrocarbons have been liberated

by the solvent (*above*). The mud logger will note whether the cut is immediate or delayed, to provide a qualitative inference of permeability.

Odor is another good indicator of hydrocarbons. If the drilling mud is ruled out as the source of an oily odor, then the presence of hydrocarbons should be investigated. However, the lack of an odor is not diagnostic of an absence of hydrocarbons, especially in gas zones.

Some rock grains may be stained through exposure to oil. The color of the stain can range from dark brown for low-API gravity oils, to colorless for high-API gravity oils and condensate. The amount of staining or *bleeding*—the slow discharge of oil—in oil-bearing cuttings or cores is a qualitative measure of permeability.

Reaction to acid can be a sensitive indicator of oil in carbonate rock samples, as long as oil-base fluids or hydrocarbons were not added to the mud system. To test for oil, the mud logger applies dilute hydrochloric acid to fragments of rock in a spot plate (*left*). The presence of oil is indicated by the formation of large bubbles as the acid reacts with carbonate in the matrix to free the oil contained within the rock's pores. In some cases, the oil will display an iridescent rainbow on the bubble's surface.



^ Reaction of carbonate rock to acid. Dilute hydrochloric acid dissolves carbonate rock, liberating any oil contained within. As it dissipates, the oil turns the clear acid brown. The three larger bubbles are a result of greater surface tension caused by the presence of oil.

Wettability can be qualitatively assessed. Failure of a sample to take on water, or the tendency of cuttings to float in water, may indicate that oil is present and that the sample is oil wet.⁷ However, samples from air-drilled wells may not wet as a result of small particle sizes and surface tension effects.

A positive result from any of these screening tests is considered an oil show, which warrants immediate notification of the company representative and geologist. The mud logger also watches for gas shows by monitoring the gas detection equipment.

The gas detection system offers near-instantaneous readings, limited only by the lag time from the bit to the surface. Suction lines transport a constant stream of air and gas from the gas trap, located at the shale shaker, to the logging unit. There, sensitive gas detection instruments process samples extracted from the drilling mud. The primary tool is a flame ionization detector (FID), which can sense hydrocarbon gas concentrations as low as 5 to 20 ppm. FID results are expressed in parts per million (ppm) of equivalent methane in air on a volume basis, where 10,000 ppm is equal to 1% methane, or 50 units.

The FID measurements are used to plot the total gas curve on the mud log. Background gas—a more or less constant, minimum level of gas—establishes a baseline on the total gas plot. The level of background gas may be any value from a few ppm to several percent, depending on formation and circulating conditions. A gas show is any significant increase in detected gas, usually also correlated with a zone of increased porosity or permeability.

The mud logger consults the gas chromatograph for more detailed analysis during oil or gas shows. Operating on an automated cycle, the chromatograph separates the gas stream into different fractions according to molecular weight. Cycle time—the amount of time it takes to cycle a gas sample through the chromatograph column—may range from less than a minute to several minutes, depending on the type of gas separation column used in the chromatograph. Commonly detected components fall within the alkane group: methane [C₁], ethane [C₂], propane [C₃], butane [C₄] and pentane [C₅]. The measurement of these light hydrocarbons helps geologists characterize reservoir fluid composition while drilling. Because each reservoir fluid is composed of different hydrocarbon species with differing molecular weights, the relative proportions of light hydrocarbons change from one fluid

type to another. The quantity of the gas recovered and the ratios of the various gases are useful in identifying zones of producible oil or gas.⁸

Basic Pressure Monitoring

Drilling crews around the world have had to contend with abnormally high formation pressures. High pressures are encountered in formations in which an impermeable layer, sealing fault, diapir or other barrier restricts natural fluid flow and pressure equilibration. In these overpressured formations, fluids trapped in the pores bear part of the weight of the overlying rock. Overpressure commonly occurs when low permeability prevents pore fluid from escaping as rapidly as required for compaction of pore space under the weight of newly deposited overburden sediments. Excess pressure builds as the weight of overburden squeezes the trapped fluid in a process referred to as undercompaction or compaction disequilibrium. This undercompaction typically occurs where there is a transition from a sand-prone to a shale-prone environment.⁹

Detection of overpressured formations is critical to the drilling process; by providing this service, mud logging plays an important role in well control. Drillers are extremely keen to recognize impending threats to well control, but the simplicity of rig floor instrumentation sometimes makes it difficult to identify subtle changes in pressure parameters. An unnoticed failure of a sensor or display on the drill floor, a distraction at the wrong time or an unexpected change in drilling routine may prevent a driller from recognizing the onset of a dangerous situation. Using surface indicators, mud loggers may be able to identify hazardous operating conditions.

Mud logging crews provide another set of eyes to monitor drilling systems while correlating multiple drilling parameters. Through examination of cuttings and diligent monitoring of ROP, gas, mud weight, bulk shale density and mud pit volume, mud loggers can frequently detect a transition from normal to potentially dangerous pressure conditions.

As the bit approaches an overpressured formation, distinct changes in compaction and porosity may be observed. Formation pressure may approach that of the bottomhole pressure (BHP). When this pressure difference decreases, ROP increases as normally overbalanced bottomhole conditions start to become underbalanced.¹⁰ Consequently, ROP is a key parameter in the detection of overpressured formations.

$$d = \frac{\log \left(\frac{R}{60N} \right)}{\log \left(\frac{12W}{10^6 D} \right)}$$

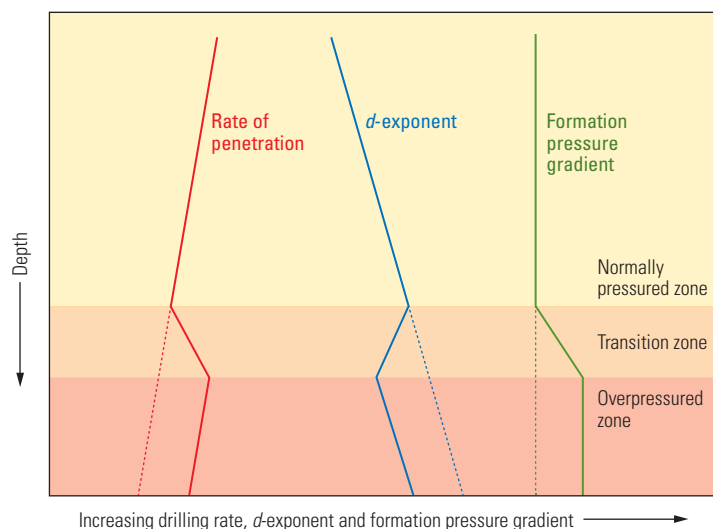
where: d = drillability exponent
 R = penetration rate, ft/h
 N = rotary speed, rpm
 W = weight on bit, lbm
 D = bit diameter, in.

^ Formula for d -exponent. The d -exponent normalizes the variables that can influence the drilling rate, making the resulting plot more sensitive to pore pressure. (Adapted from Jorden and Shirley, reference 11). The d -exponent varies inversely with the rate of penetration. Variations on the original equation have been developed since its publication in 1966; these variations account for changes in mud weight or bit wear. (Rehm and McClendon, reference 12.)

Shale porosity has long been considered a reliable indicator of abnormal formation pressure. Because the weight of overburden causes shale to become more compact with depth, ROP normally decreases with depth. If the drilling rate increases in shale, the driller and mud logger might reasonably suspect that porosity is increasing and that the bit may be entering an overpressured zone.

However, numerous factors influence ROP; weight on bit, mud weight, rotary speed, bit size and bit condition also affect drilling rate.¹¹ To account for these mechanical variables, the mud logger computes a drillability exponent, or d -exponent (above). Some mud loggers use a corrected d -exponent (dcs), which factors in

7. Wettability is the preference of a solid surface to be in contact with one liquid rather than another. Intermolecular interactions between the solid surface and the liquid control wetting behavior. For more on wettability: Abdallah W, Buckley JS, Carnegie A, Edwards J, Herold B, Fordham E, Graue A, Habashy T, Seleznev N, Signer C, Hussain H, Montaron B and Ziauddin M: "Fundamentals of Wettability," *Oilfield Review* 19, no. 2 (Summer 2007): 44–61.
8. For more on chromatography and gas ratio analysis: Haworth JH, Sellens M and Whittaker A: "Interpretation of Hydrocarbon Shows Using Light (C₁–C₅) Hydrocarbon Gases from Mud-Log Data," *AAPG Bulletin* 69, no. 8 (August 1985): 1305–1310.
9. Bowers GL: "Detecting High Overpressure," *The Leading Edge* 21, no. 2 (February 2002): 174–177.
10. Dickey PA: "Pressure Detection: Part 3. Wellsite Methods," in Morton-Thompson D and Woods AM (eds): *Development Geology Reference Manual*. Tulsa: The American Association of Petroleum Geologists, AAPG Methods in Exploration Series no. 10 (1992): 79–82.
11. Jorden JR and Shirley OJ: "Application of Drilling Performance Data to Overpressure Detection," *Journal of Petroleum Technology* 18, no. 11 (November 1966): 1387–1394.



▲ Effects of overpressure on drilling rate and d -exponent. Through a normally pressured shale interval, ROP (red line) generally decreases with depth. The d -exponent (blue line) tends to increase with depth, following a normal compaction trend. Deviations from these trends may be related to undercompaction and may signal that the bit is encroaching on an overpressured zone.

changes in mud weight or bit wear.¹² After calculating the d -exponent to normalize the ROP, the mud logger can view drillability as a function of rock strength and the density of the drilling fluid.

As compaction and rock strength increase with depth, the d -exponent increases when drilling through a uniform lithology with no changes in mud overbalance or bit performance. A plot of the d -exponent with depth should roughly mirror the ROP, showing an inverse relation to the drill rate (above). A drilling break would plot as a reversal in the slope of the d -exponent.

The arrival of gas in the mud is another indication of compaction disequilibrium. If formation pressure exceeds the pressure applied by the column of mud, formation fluids will begin to flow into the wellbore. A rapid influx of fluids is called a kick, and marks the beginning of serious well control problems. If formation fluid—especially gas—flows into the wellbore unabated, the effects will soon cascade. The influx will lower the overall mud column weight, reducing the effective pressure against the flowing formation, thereby permitting the formation to flow at a greater rate, leading to a blowout.

Mud loggers may try to interpret overpressure clues from a number of parameters. An increase in the temperature of the mud returns may result from faster drilling and increased cavings in undercompacted shales. Gas levels may

rise as a result of methane dissolved in the pore water of some overpressured shales. Gas escaping from the cuttings is detected at the mud logging unit as an increase in total gas. This indicator may be misleading, however, because increases in total gas may result from oil- or gas-bearing formations or organic-rich shales. The increase in porosity that is characteristic of undercompacted shales causes lower shale density than is found in normally compacted shales. The mud logger uses a density measuring device in the logging unit to determine the density of shale cuttings at regular intervals.¹³

An increase in return flow, coupled with rising levels in the mud tanks, indicates a reflux of drilling fluids, with greater volumes of mud flowing out of the hole than were pumped into it. Pit level and flow rate sensors monitored at the drill floor and logging unit will trigger an alarm when they detect a mud level change, prompting the drilling crew to shut off the mud pumps, check for flow and prepare to close the blowout preventer.

At the opposite end of the spectrum is a decrease in mud levels, which indicates that the mud pumps are sending more fluid downhole than is being circulated back to the surface. This lost circulation may indicate that the formation has fractured and can have serious repercussions, depending on the rate of fluid loss.¹⁴ If the mud

level drops too far, the decrease in the hydrostatic pressure downhole may allow formation fluids to enter the wellbore, causing a kick similar to drilling into an overpressured zone.

A kick may also be indicated by an increase or decrease in drillstring weight. A small infusion of formation fluid can reduce the buoyancy of the fluid in the annulus; a sensitive weight sensor may indicate this change as an increase in drillstring weight. Given a substantial kick, however, formation fluid may enter the borehole with enough force to push the drillpipe upward, causing a marked decrease in indicated drillstring weight.

The ability to warn drilling crews of impending trouble is heavily dependent on the mud logger's capacity for monitoring changes in drilling parameters. This capability could never have been realized without the extra layer of hyper-vigilance derived from numerous sensors installed at critical points around the rig.

Moving into the 21st Century

Early mud loggers grew attuned to the sounds of the drilling rig and could often tell what was happening simply by the clang of the driller's tongs, the revving of the drawworks engine and the squeal of the driller's brake. Any variation in the normal routine and rhythms of the rig was cause for investigation. Today, robust, highly sophisticated sensors acquire data at several times per second while a context-aware processing system helps the mud logger piece it all together.

Through the years, an impressive array of sensors has been developed or adapted for use by advanced mud logging companies. One such company, Geoservices, a Schlumberger company, is an industry leader in mud logging technology.¹⁵ Over its 53-year history, Geoservices has developed or acquired a wide variety of sensors to measure and record critical drilling performance and circulation system parameters. Most sensors are intrinsically safe for operating in hazardous conditions and must be robustly constructed to ensure reliable operation in harsh drilling environments and climates. Sensor signals are converted from analog to digital as close to the

12. Rehm B and McClendon R: "Measurement of Formation Pressure from Drilling Data," paper SPE 3601, presented at the SPE Annual Meeting, New Orleans, October 3–6, 1971.

Lyons WC (ed): *Standard Handbook of Petroleum & Natural Gas Engineering*, vol 2. Houston: Gulf Professional Publishing (1996): 1045.

13. Dickey, reference 10.

14. For more on mud loss prevention and remediation: Cook J, Growcock F, Guo Q, Hodder M and van Oort E: "Stabilizing the Wellbore to Prevent Lost Circulation," *Oilfield Review* 23, no. 4 (Winter 2011/2012): 26–35.

15. Geoservices was acquired by Schlumberger in 2010.

sensor as possible to prevent problems associated with analog signal transmission and a multitude of cables running across the rig floor.

Pressure sensors measure a variety of crucial parameters. These sensors can be fitted to key pieces of rig equipment to obtain measurements such as weight on hook, WOB, rotary torque, standpipe pressure, casing pressure and cement unit pressure.

By measuring small movements of the drawworks drum, the drawworks sensor helps the mud logger track the movement of the drillstring and the position of the bit while drilling or tripping (right). This sensor is fitted onto the main shaft of the drawworks. Drawworks sensor outputs help the mud logger determine drilling rate, hook position and bit position.

Noncontact proximity sensors monitor pump strokes and rotary speed. Pump strokes are used to calculate mud flow rates, which are essential for optimization of drilling hydraulics, estimation of lag time and various kick control functions. Monitoring of rotary speed (rpm) is necessary for assessing drilling performance and calculating the *d*-exponent. The proximity sensor emits an electromagnetic (EM) field and uses EM induction to detect the passage of a metal activator.

Variations in rotary torque often provide the first indications of problems with downhole drilling equipment. For a given rotary speed, a gradual increase in torque might signal that the drill bit is worn and should be replaced. Mud loggers can also use torque variations to identify formation changes while drilling. A rotary torque sensor uses a transducer, which is clamped around the cable feeding the electric motor that powers the rotary table or topdrive. The electric current drawn by the motor is proportional to the rotary torque applied to the drillstring.

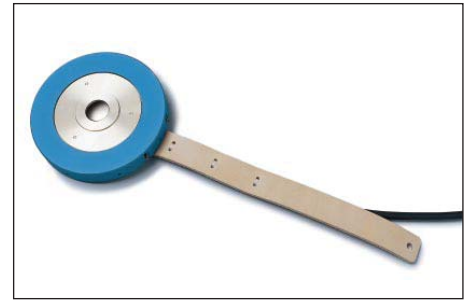
Detection of changes in mud pit level is key to the safety of the drilling process. The ultrasonic pit level sensor is positioned over the mud pits and measures fluid level. This sensor emits an ultrasonic wave that reflects off the surface of the liquid (right). This sensor is light, compact, accurate and highly reliable, requiring no moving or immersed parts. Precise measurement of the time it takes for the ultrasonic signal to return to the sensor gives the distance between the sensor and the level of liquid in the pit. On floating rigs, multiple sensors may be installed in each pit to account for variations in mud level caused by ocean wave motion.

Density sensors provide rapid, accurate measurements of drilling fluid density; they can detect slight changes in mud weight, enabling the mud logger to alert the drilling crew to an influx of lower-density formation fluids into the well. The density sensors are also used to monitor the addition of weighting material or fluid to the mud system. Mud density is measured by two pressure sensors immersed at different depths in the mud pit and calculated from the pressure differential and depth between the sensors.

Three types of flow sensors are available for continuous monitoring of drilling fluid flow:

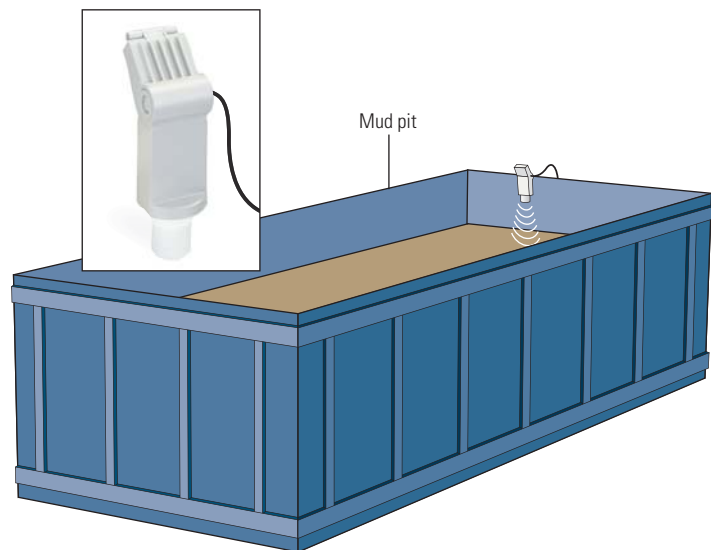
- The mud flow paddle measures the height of the mud in the mud return flowline. When connected to the logging system computer, the sensor provides a continuous chart of relative height. The mud logger can set alarms for flow height above and below preselected limits.
- The electromagnetic flowmeter is a volumetric flowmeter that operates on the principle of magnetic induction. It can be installed on the standpipe to measure flow into the well and on the return flowline to measure flow out of the wellbore. Each sensor unit replaces a short section of the pipe on which it is mounted.

Each sensor consists of a pair of circular electrodes flush with the inside of the pipe. When the sensor is energized, a magnetic field is established at right angles to the pipe axis,

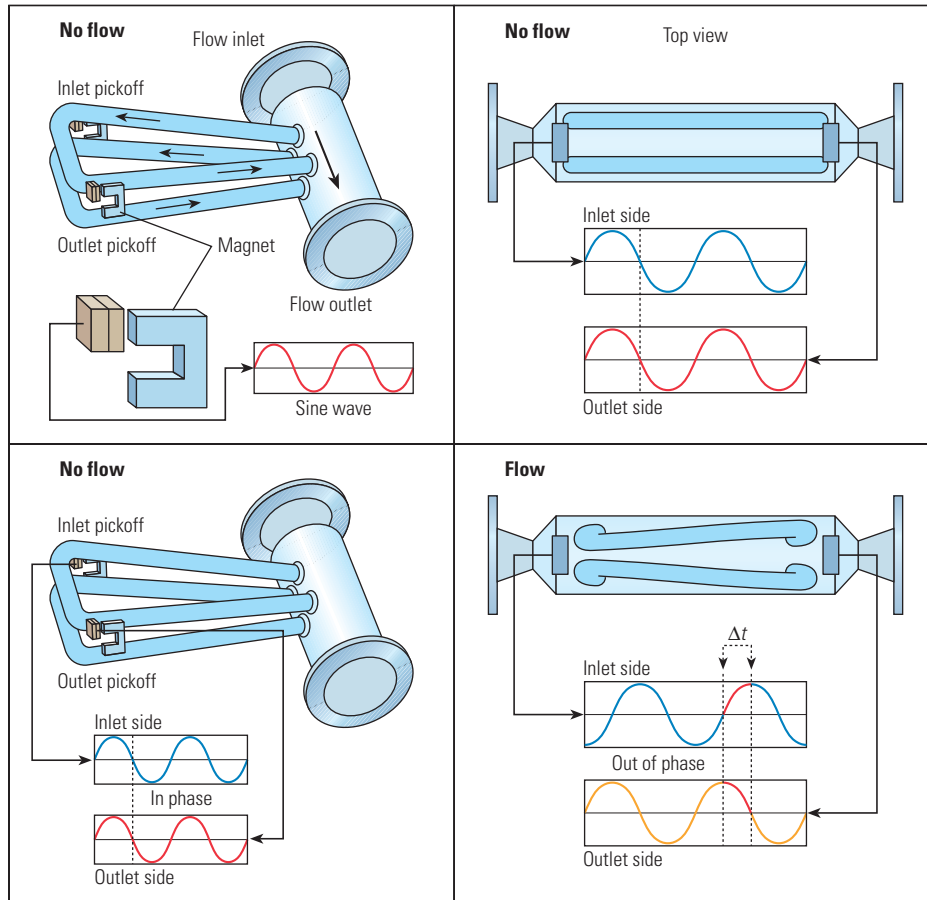


^ Drawworks sensor. This sensor consists of a disk that rotates in harmony with movements of the cable drum. Movements of the disk are detected by proximity sensors, which send pulses to the main processor in the logging unit.

creating a potential difference between the two electrodes that is proportional to the fluid flow rate. The electromagnetic flowmeter operates in water-base muds or in muds in which the continuous phase is conductive. Connection to the logging system computer enables real-time monitoring and permanent recording of the flow parameters as well as automated calculation of differential flow, which is essential for reliable detection of small-volume kicks or losses.



^ Pit level sensor. This device (inset) emits a series of ultrasonic pulses to detect changes in fluid level in the mud pit.



^ Coriolis flowmeter. Coriolis meters are installed in the flowline. When there is no flow, current through the pickoffs (*top left*), generates sine waves on both inlet and outlet sides of the meter (*bottom left and top right*) that are in phase with each other. Fluid moving through the tubes causes them to twist in opposing directions (*bottom right*) and also causes the sine waves to go out of phase by a factor Δt , which can be converted to mass flow rate.

- The Coriolis flowmeter accurately measures mass flow, temperature and density of a circulating fluid, gas or slurry at low to moderate pressures. The sensor, typically installed on a bypass channel added to the return flowline, uses the Coriolis effect to measure flow (*above*). Fluid enters the sensor and passes through a pair of flow tubes, which are free to vibrate and twist under the influence of the fluid flow. Flow is measured by quantifying the amount of twist in the flow tubes, which is proportional to the mass flow rate of the fluid. The density of the fluid is obtained by measuring the resonant frequency of vibration of the flow tubes. The measured values are automatically compensated for temperature changes.

The temperature of the circulating drilling fluid can provide clues to changing downhole conditions. Temperature sensors are usually placed in the suction mud pit (designated as “temperature in”) and in the shale shaker header

box to obtain flowline temperature (designated as “temperature out”). From the difference between “out” and “in” values, the temperature gradient can be calculated to help logging crews locate transition zones and other geologic boundaries.

The resistivity sensor measures drilling fluid electrical resistivity, which reflects the salinity of the fluid. The sensors are installed in the suction pit and shale shaker header box. Mud salinity may change when drilling through bedded salts or salt domes, when passing through fault zones, and when drilling zones of transition to abnormal pressures where formation water flows into the mud column. This system enables accurate and linear measurement of conductivity from 0 to 300 mS.

Today’s mud logging units monitor a wide range of surface sensors used to ascertain downhole conditions or evaluate rig performance. These sensors enable the mud logger to recognize changing conditions that could enhance or jeopardize a prospect.

Advanced Services

New sensor technology is paving the way for improving drilling performance and increasing the value of the data extracted from the mud. Geoservices mud logging technology is focused on two main areas: formation evaluation and drilling support.

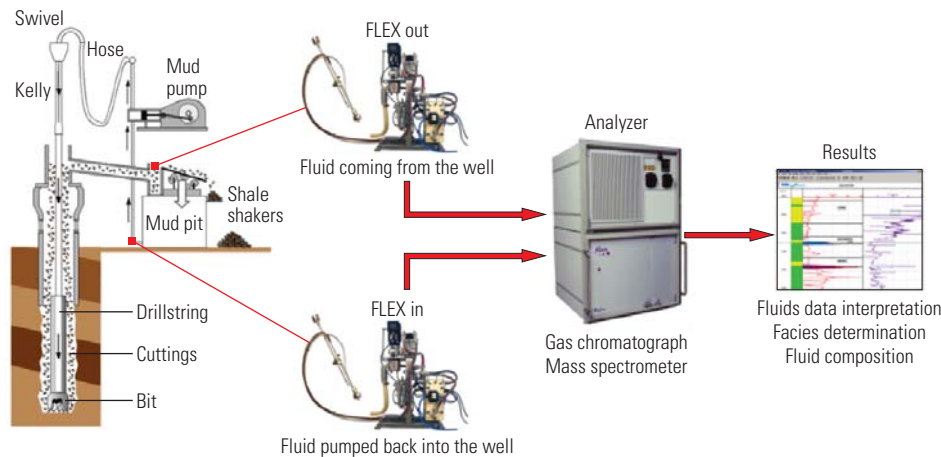
Formation evaluation services can now go beyond analyses of rock cuttings and fluids to identify lithology and potential pay zones. To supply advanced mud gas sampling and chromatography, Geoservices has developed the FLAIR fluid logging and analysis service for wellsite geochemical evaluation. Drilling support services provide a level of analysis of surface data—beyond that of basic pressure monitoring services—to enhance safety and optimize drilling operations. The PreVue real-time geopressure service is designed to help reduce the risks of kicks, mud losses and other well control problems. And Thema drilling operations support and analysis service provides

up-to-date analysis of drilling mechanics, hole condition and rig performance.

FLAIR advanced mud gas logging—During the past 10 years, advances in mud logging technology have significantly improved the quality and utility of wellsite formation evaluation data. Today, high-resolution gas chromatography and mass spectrometry provide data and interpretative capabilities that enable quantitative evaluations of key formation parameters. FLAIR fluid logging and analysis in real time gives early information pertaining to formation fluid composition. Integration of FLAIR data with data obtained by other formation evaluation techniques enables more-accurate assessments of hydrocarbons in the formation.

The FLAIR system analyzes hydrocarbons extracted from the drilling mud under constant thermodynamic conditions. These hydrocarbons are continuously analyzed to obtain a quantitative evaluation of the light gases C_1 through C_5 , while also providing qualitative information on heavier components C_6 through C_8 , including methylcyclohexane and the light aromatics benzene and toluene.¹⁶ Other nonhydrocarbon components, such as helium, hydrogen, carbon dioxide and hydrogen sulfide can also be monitored.

Specialized mud gas extraction equipment is a key component of the FLAIR system. The FLEX fluid extractor continuously samples mud from the flowline as the mud returns from the well. The FLEX extractor heats mud samples to a constant temperature under constant pressure and volume conditions. This method provides a steady air-to-mud ratio inside the extraction chamber, creating an extremely efficient and repeatable process. The capability to heat the sample can be particularly important in deepwater environments, where mud return temperatures may range from 10°C to 15°C [50°F to 59°F]. At low temperatures, there is not enough



^ Arrangement of FLEX extraction units. Using specialized gas extraction units placed in the discharge and suction lines, the FLAIR analysis system compares the two gas streams to correct for any recycled gas that the mud system's degassing units failed to remove.

inherent energy in the system to efficiently liberate the heavier gas components from the mud. Traditional mud gas extractors that do not heat the sample may yield inaccurate data because more of the gas is left in the mud during the extraction process.

With the FLEX extraction process, the FLAIR mud gas logging system operates under constant thermodynamic conditions, enabling calibration of the extraction efficiency for the C_1 to C_5 components. The heavier hydrocarbons, C_6 to C_8 , are not as easily extracted, but their presence can be detected qualitatively. The calibration is coupled with a correction that accounts for any gas that might have been recycled through the mud system. This is achieved by placing a second FLEX unit in the pump suction line, the point at which the mud is pumped back into the well (above). In this manner, the fraction of hydrocarbons recycled with the mud and pumped back into the well can be quantitatively measured. Correction for recycled gas is possible because the extraction conditions are the same for both FLEX units.

Extracted hydrocarbons are fed to an advanced gas chromatograph–mass spectrometer (GCMS) analyzer, which detects and analyzes gases at the parts-per-million (or micrograms-per-gram) level. The mass spectrometer enables the FLAIR analyzer to detect and differentiate between coeluting peaks created by the various ion currents that characterize components extracted from the mud. This leads to a very short analysis time—85 s for analysis up to C_8 , including differentiation of several isomers.

Comparisons between pressure-volume-temperature (PVT) analysis of actual downhole fluids with results obtained through FLAIR analysis of C_1 to C_5 components show a close match. This capability was demonstrated during a collaboration between Shell and Geoservices, in which PVT and FLAIR data from Gulf of Mexico wells were found to be comparable, whereas a traditional mud gas logging system consistently underestimated the concentrations of the C_{2+} gas species.¹⁷

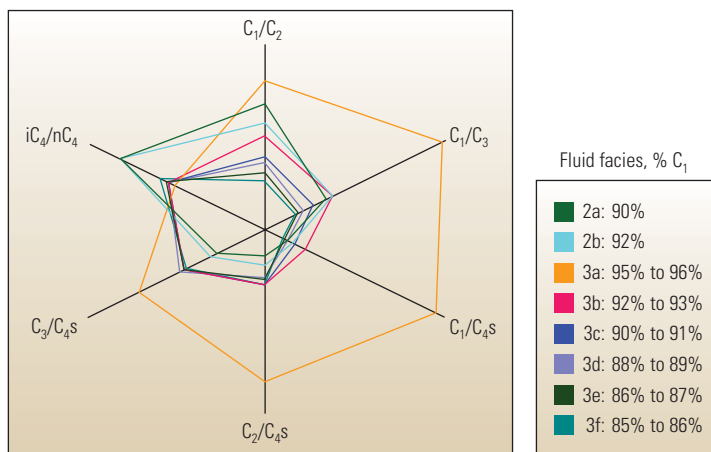
Among other capabilities, the FLAIR service can help geoscientists differentiate between different fluid types. As a bit penetrates a reservoir, an increase in gas density measured at the surface may indicate a transition from gas cap to oil leg. This increased density is caused by a proportional increase in heavier gases (C_{3+}) compared with the lighter C_1 and C_2 components. Measurements of heavy components and their relative proportions to the light fraction are used to calculate the hydrocarbon balance (Bh) and wetness (Wh) ratios, which help geoscientists discriminate between oil and gas.¹⁸

The FLAIR service was run on an offshore UK appraisal well drilled for Hess Corporation and partners Chevron, DONG Energy and OMV. Two of the operator's key objectives for the well were to confirm the volume of hydrocarbons in place within the main reservoir and to investigate the presence of hydrocarbons in certain formations above and below this reservoir. After the pilot hole was successfully drilled, a sidetrack was drilled and the well was landed horizontally in the main reservoir target interval, designated as

16. Light hydrocarbons such as C_1 to C_5 are easily removed by the mud gas extraction process, so their concentrations can be assessed quantitatively. The heavier C_6 to C_8 hydrocarbons are more difficult to remove from the fluid by this process. Their presence can be detected but not easily quantified, so a qualitative measurement is provided.

17. McKinney D, Flannery M, Elshahawi H, Stankiewicz A, Clarke E, Breviere J and Sharma S: "Advanced Mud Gas Logging in Combination with Wireline Formation Testing and Geochemical Fingerprinting for an Improved Understanding of Reservoir Architecture," paper SPE 109861, presented at the SPE Annual Technical Conference and Exhibition, Anaheim, California, USA, November 11–14, 2007.

18. $Bh = [(C_1 + C_2) / (C_3 + iC_4 + nC_4 + C_5)]$.
 $Wh = [(C_2 + C_3 + C_4 + C_5) / (C_1 + C_2 + C_3 + C_4 + C_5)] \times 100$.
 For more on these ratios and their interpretation: Haworth et al, reference 8.

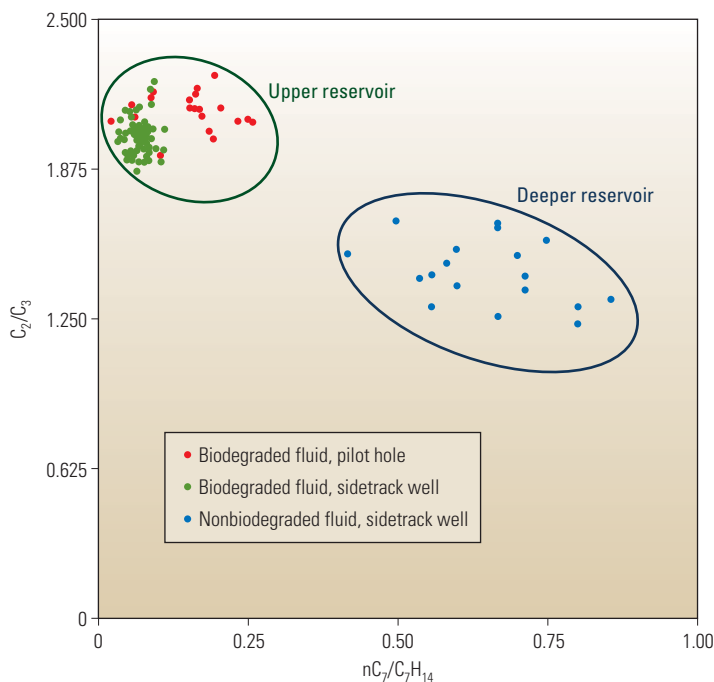


^ Fluid facies characterization. Variations in fluid composition produce distinctive star plots that can be classified as different fluid facies. This star diagram highlights different levels of heterogeneity. The lightest fluid was encountered in the 3a facies, whereas heaviest fluids were found in facies 3e and 3f.

the S3 horizon. The sidetrack well raised a number of questions pertaining to vertical connectivity, fluid variability, presence of altered and unaltered fluids and geosteering uncertainties within the horizontal section.

Hess investigated potential hydrocarbon zones where gas peaks were recorded above background level. FLAIR analysis of gases from

these zones helped the operator divide them into distinctive fluid facies. These facies were defined by graphing gas ratios on star diagrams—multivariate plots in polar coordinates—to depict chemical composition and highlight their differences (above). Based on these analyses, the operator identified several distinct fluid facies from different horizons within the well.



^ Recognizing fluid differences. Hess scientists identified two distinct fluid families, based on the level of fluid alteration. The hydrocarbon ratio analysis confirmed the fluid in an upper reservoir was biodegraded, whereas the fluid in a deeper reservoir in the well was unaltered.

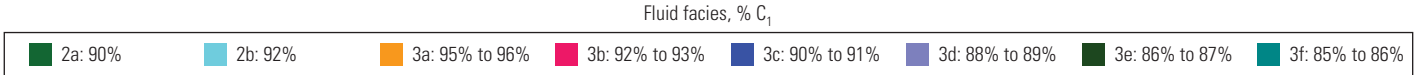
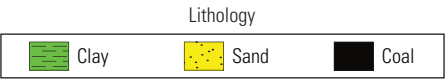
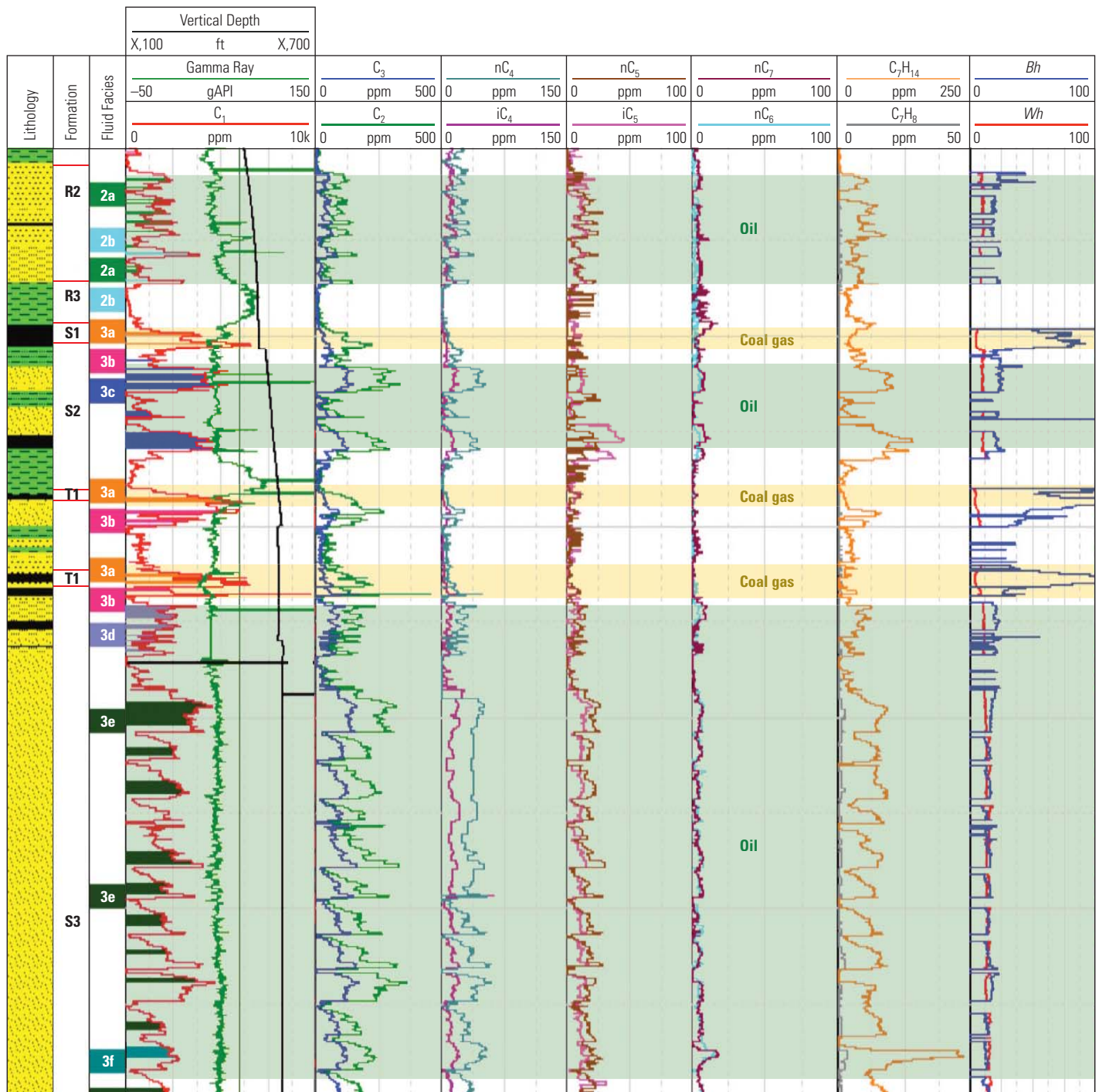
The FLAIR service also helped the operator evaluate a formation's potential for producing oil or gas. The ratio of heavy to light fractions was used to calculate the hydrocarbon balance and wetness ratios. Another potential indicator was the appearance of methylcyclohexane [C_7H_{14}], a member of the naphthenic family that usually is present in the liquid phase (next page).

In addition, the operator sought to distinguish between biodegraded and nonbiodegraded fluids in the reservoir. Biodegradation can affect both the quality of hydrocarbons and their producibility.¹⁹ Among other effects, biodegradation can raise oil viscosity, decrease API gravity and increase asphaltene, sulfur and metals content. In addition, biogenic gas may override oil in a reservoir, moving updip to disrupt existing reservoir fluid gradients. This influx modifies the gas/oil ratio, creating compositional variations. Gradient disruptions from charging and recharging may indicate the presence of compartments.

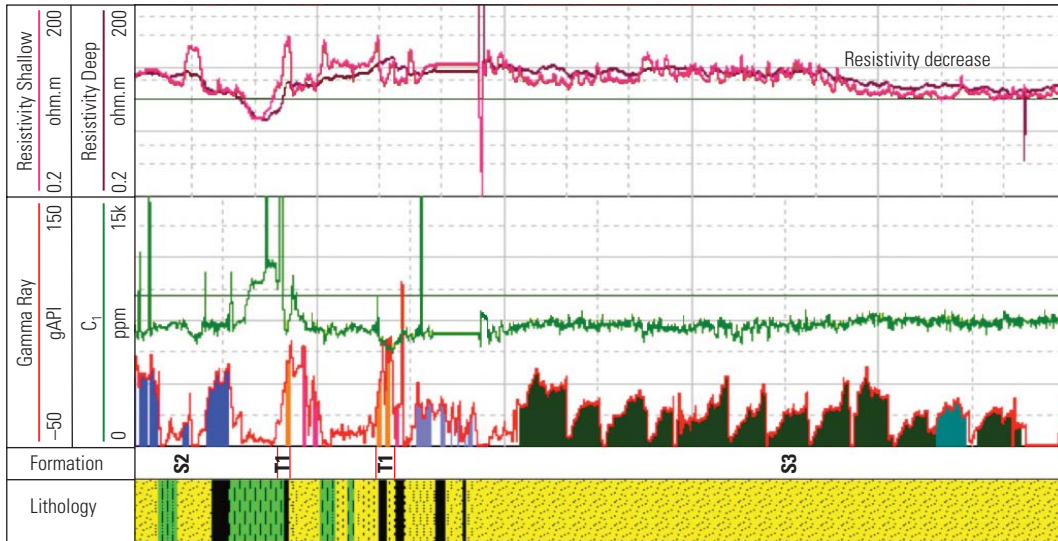
In a study conducted prior to spudding the well, Hess evaluated PVT analyses obtained from offset wells to assess the effects of biodegradation in the reservoir. These analyses helped to identify markers that could prove useful in recognizing alterations resulting from biodegradation. The study indicated that specific ratios of heptane [nC_7], methylcyclohexane [C_7H_{14}] and toluene [C_7H_8] were common to the wells in which biodegradation was observed. The C_2/C_3 ratio was found to be another useful indicator of early-stage biodegradation because C_3 is one of the first components that bacteria attack and remove; in a later stage they remove the C_2 .

FLAIR analysis provided quantitative composition only in the C_1 to C_5 range and provided qualitative evaluations of the heavier hydrocarbons. In the Hess well, these results showed low values of the nC_7/C_7H_{14} ratio, which is in line with biodegradation effects observed in reservoir fluids from offset wells. When extremely low values of toluene were detected—close to the sensitivity of the analyzer—a change in the analysis routine was called for. The C_7H_8/nC_7 ratio was replaced by a C_2/C_3 ratio, providing a clear differentiation between biodegraded and unaltered fluids (left).

19. For more on biodegradation in the reservoir: Creek J, Cribbs M, Dong C, Mullins OC, Elshahawi H, Hegeman P, O'Keefe M, Peters K and Zuo JY: "Downhole Fluids Laboratory," *Oilfield Review* 21, no. 4 (Winter 2009/2010): 38–54.



^ Fluid facies log. Precise hydrocarbon measurements are obtained through FLAIR gas analyses and are used to distinguish between fluids produced from different reservoir intervals. The resulting fluid facies are numbered sequentially, with a letter indicating subfacies (Track 3 and legend). Measurements of the C₁ to C₇ components (Tracks 4 to 8) are used to calculate hydrocarbon balance (*Bh*) and wetness (*Wh*) ratios (Track 10). In this well, methylcyclohexane [C₇H₁₄] was also useful in determining the presence of a liquid phase (Track 9). The R2 and R3 formations (Track 2) are characterized by fluid facies 2, while the other formations contain fluids from facies 3. The targeted S3 reservoir was fairly homogeneous, its fluids being relatively light in the C₁ to C₅ range, but with a proportionally higher abundance of C₇H₁₄, which suggested the presence of a liquid phase. The coal seams S1 and T1 were consistently characterized by high gas levels, with the gas ranging between 95% and 96% C₁—but without methylcyclohexane.



^ LWD log. During drilling through the reservoir section, FLAIR gas analysis (Track 3) helped to ease concerns about a decrease in resistivity. FLAIR analysis confirmed that the well had not exited the reservoir zone.

The FLAIR services also proved useful as an aid to geosteering. While the horizontal section was being drilled, a decrease in resistivity was observed within the reservoir zone (above). This drop might have signaled an impending roof or base exit from the targeted section, or it might have indicated that the bit was entering the water leg of the reservoir. However, fluid facies analysis performed in real time showed that the fluid remained unchanged, indicating that the wellbore had not exited the oil zone. The resistivity decrease was attributed to increasing irreducible water saturation within the oil zone.

PreVue real-time geopressure service—The PreVue services provide prespud pressure prediction along with wellsite monitoring of pore pressure and wellbore stability. Far in advance of rig mobilization, pressure specialists collect data from nearby offset wells and seismic surveys. They analyze well logs, pressure tests and mud reports to create a vertical stress model of each wellbore, then correlate velocity and log response to wellbore pressure anomalies.

After creating a 3D seismic interval velocity model from local and regional seismic data, the pressure specialists calibrate the model using acoustic logs and checkshot surveys from offset wells.²⁰ Next, they conduct a velocity volume analysis, computing normal compaction trends (NCTs) and creating pore pressure and wellbore stability models. Leakoff test data from offset wells provide control points for modeling the fracture gradient. These models help the PreVue pressure engineers identify potential zones of abnormal pressure, determine kick tolerances, develop mud weight windows and project where casing points should be set (next page).

Once drilling commences, PreVue wellsite pressure engineers closely monitor ROP and gas readings as well as LWD and MWD logs; they update pressure plots, revise trend lines and watch for variations from the predrill model. Using this information, they can apprise the wellsite company representative of impending problems.

As drilling proceeds, LWD provides important data for interpreting changes in pressure

regimes. The sonic velocity, density and resistivity logs are especially useful for pore pressure and fracture gradient interpretation. Although a number of factors—such as washouts, formation fluid type and anisotropy—can influence log response, in general, these tools respond to changes in rock porosity.

When PreVue engineers observe a porosity increase as depth increases, they immediately notify the driller and company representative. Quick detection of influx and changing gas content is a critical task for the PreVue engineer.

A typical response would be to increase mud weight until the influx is under control. However, this strategy is not without risk, such as unintentional fracturing of the formation that can result in sudden mud loss. Increasing the mud weight may create new fractures or open existing fractures and force mud into the formation. In permeable formations, this can lead to fluid loss. Apart from the cost of losing expensive drilling fluid, significant mud loss from the annulus can lead to lower hydrostatic pressure and result in a difficult well control situation.

20. Following normal compaction trends, seismic interval velocities increase with depth. Decreases in velocity with depth may be used to identify potential zones of abnormal formation pressure.
 21. Umar L, Azian I, Azree N, Ali ARM, Waguih A, Rojas F, Fey S, Subroto B, Dow B and Garcia G: "Demonstrating the Value of Integrating FPWD Measurements with Managed Pressure Drilling to Safely Drill Narrow Mud Weight Windows in HP/HT Environment," paper SPE/IADC 156888, presented at the SPE/IADC Managed Pressure Drilling and Underbalanced Operations Conference and Exhibition, Milan, Italy, March 20–21, 2012.

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 22. For more on look-ahead VSP methods: Borland W, Codazzi D, Hsu K, Rasmus J, Einchcomb C, Hashem M, Hewett V, Jackson M, Meehan R and Tweedy M: "Real-Time Answers to Well Drilling and Design Questions," *Oilfield Review* 9, no. 2 (Summer 1997): 2–15.
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Turning on mud pumps raises the pressure of the mud, and this phenomenon can be regarded as a virtual increase in the mud density. Management of this gap between the effective static density (pumps off) and effective circulating density (pumps on) and its relationship to the formation pressure and rock strength is a key to successful drilling. The objective of the PreVue service is to balance the mud density—both static and circulating—between the formation pressure and the rock strength.

In 2011, Petronas Carigali Sdn Bhd drilled the high-pressure, high-temperature SBD-2 well, in the Malay basin offshore Malaysia. Based on previous experience in the area, drillers expected that they would have to contend with a narrow mud weight window constrained by pore pressure and fracture pressure.²¹ An earlier offset well, the SBD-1, experienced pressure problems accompanied by heavy mud losses, which prevented the well from reaching its objective.

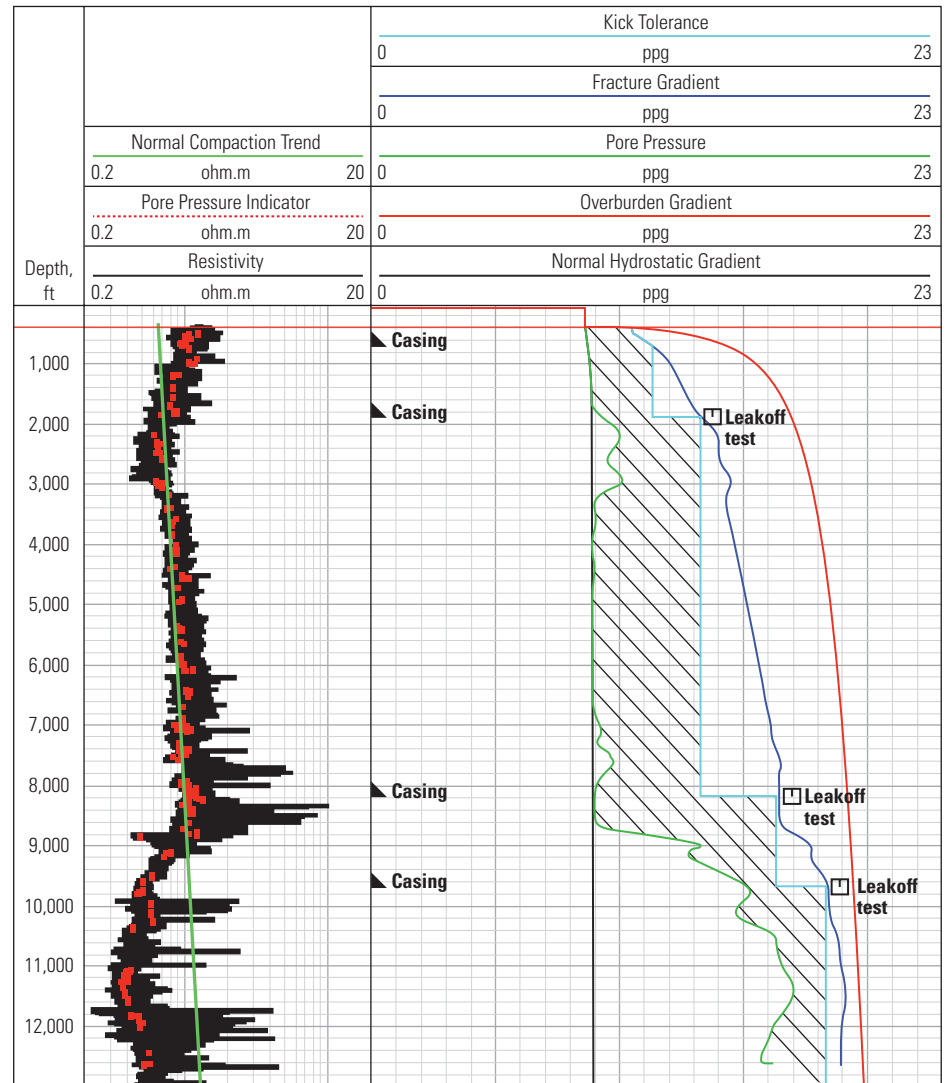
Using logs from the SBD-1 well, Petronas geologists were able to identify the onset of abnormal pore pressure. Before spudding the SBD-2 well, Petronas wanted to determine the depth of the transition from a lower pressure gradient to a higher pressure gradient. PreVue pressure specialists analyzed seismic data to ascertain the top and base of this pressure ramp. A 3D seismic volume of the area was analyzed and the velocity data from offset wells were extracted and compared with wireline and LWD data. These data were used to compute overburden gradients and normal compaction trends in offset wells, which were then integrated into a velocity model across the prospect location. Velocity values from the prospect location and other sites were analyzed to determine the depth at onset of abnormal pressure and the magnitude of pressure. The difference between pore pressure and kick tolerance left the driller with an extremely narrow equivalent mud weight window of just 1 to 1.5 lbm/galUS [0.12 to 0.18 g/cm³].

During subsequent planning sessions, the operator elected to obtain borehole vertical seismic profile (VSP) data after each casing run. This intermediate VSP data from the wellbore could be obtained in the relatively safe environment of the SBD-2 cased hole. Moreover, it would allow the project team to make time-depth conversions in their original model, which relied on surface seismic data. The VSP data would also allow the operator to identify any changes in the model and could be used as a tool for gauging the pore pressure profile ahead of the bit. This valuable look-ahead information would guide the drilling team's strategy for drilling the well to its target.²²

Drilling progress toward the pore pressure ramp was tracked by integrating LWD resistivity logs and *d*-exponent plots, along with emphasis on gas measurements and trends. Prior to drilling into the pressure transition zone, the operator ran a zero-offset VSP to update previous estimates of pore pressure. Based on this VSP data, high- and low-pressure cases were developed with the same normal compaction trend line used to generate pore pressure curves from seis-

mic velocity. Both cases indicated that the range for increase in pore pressure gradient was around 1 lbm/galUS. This gave the drilling team a clearer picture of what lay ahead and reinforced confidence in the computed model.

The interval between intermediate casing and TD in the SBD-2 well was drilled in two sections. The first of these was drilled using a 10½-in. bit and a 12¼-in. underreamer. After 9¾-in. casing was set, the second section was



▲ Predrill analysis of an offset well log. Overpressured zones or intervals of inhibited compaction are characterized by increased porosity, which can be identified through log responses from nearby offset wells. Pore pressure indicators (red dots, Track 1) are based on average shale resistivity (black) and help to establish a normal pore compaction trend line (green). Deviations from the normal compaction trend may indicate abnormal pressure. PreVue pore pressure studies evaluate seismic data and logs, leakoff tests and mud reports from offset wells to predict the onset of abnormal pressure, its magnitude and the range of mud weights that can be used to control it. In this example, deviations from the normal compaction trend start at about 8,800 ft. The equivalent mud weight curves (Track 2) display a corresponding pressure behavior. Kick tolerance (light blue) is dictated by the weakest formation exposed in open hole. The fracture gradient (dark blue), pore pressure (green), overburden gradient (red) and normal hydrostatic gradient (black) have been calculated to establish an allowable mud weight window (hatched) bounded by the kick tolerance and pore pressure curves.

drilled to TD using an 8½-in. bit and a 9½-in. underreamer. The underreamers increased the annular volume, which reduced circulating pressures in the annulus and lowered the ECD, thus counteracting the effects of the heavy muds. Throughout this interval, the mud weight was maintained close to the

estimated pore pressure profile and ECDs were maintained close to the fracture gradient. Any pressure increase in which downhole ECD exceeded kick tolerance resulted in seepage losses and thus gave the drilling team a reliable indicator for maintaining downhole pressures.

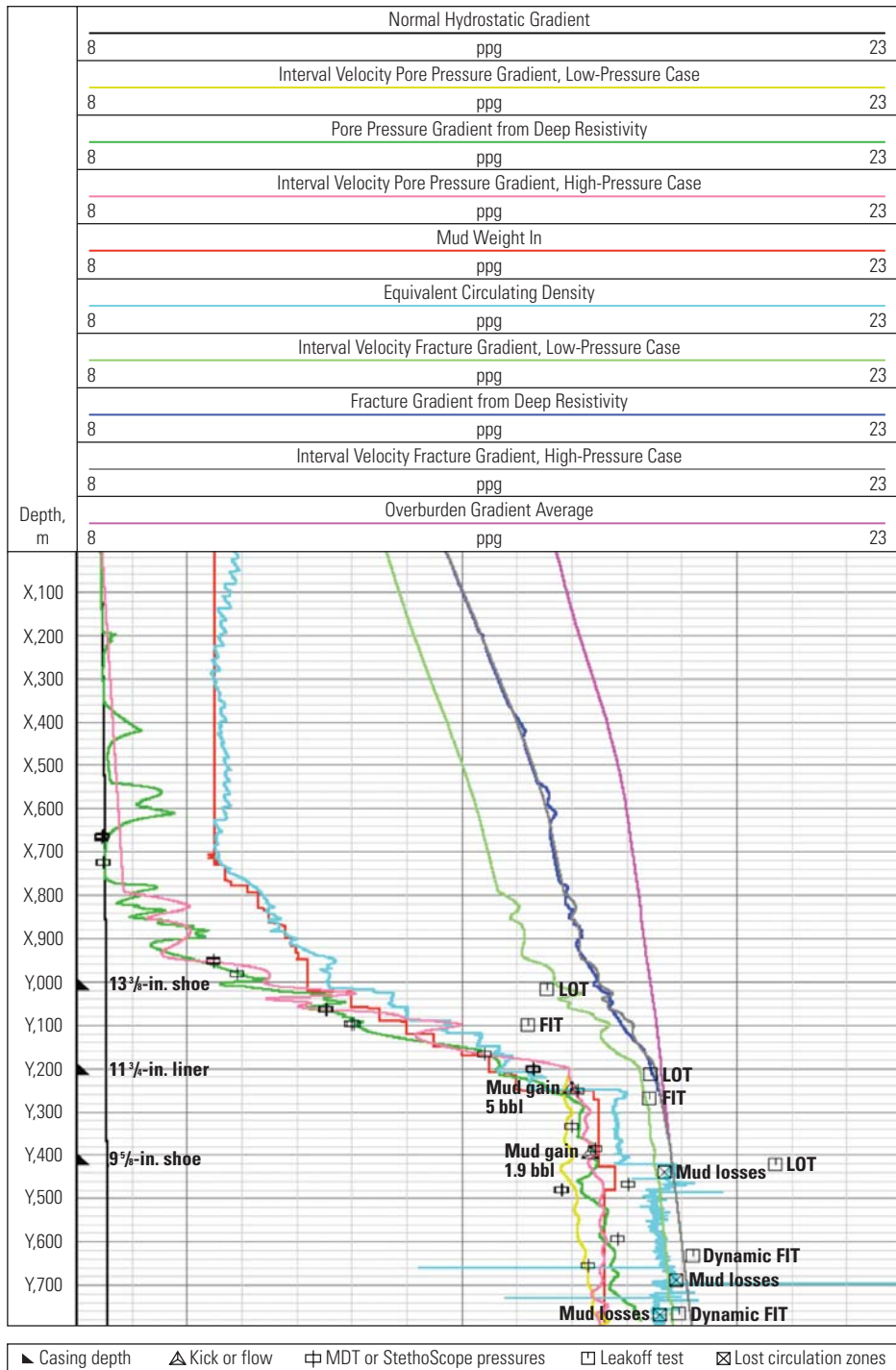
PreVue engineers also used gas measurements to obtain accurate indications of mud balance. As the well neared TD, gas peaks were observed following pump stoppages. PreVue engineers analyzed these gas increases and found that, instead of a troublesome influx resulting from low mud weight, these gas peaks were caused by well breathing.

Well breathing may be observed in some wells following brief stoppages of the mud pump. When mud weight approaches the equivalent of the fracture gradient, small fractures can develop in weak formations or along the interface between rock layers. While mud pumps are turned on, the fractures may open, allowing drilling fluid to enter. Light gases diffuse from the formation into the drilling fluid. When the pumps are turned off briefly, such as during a pipe connection, the fractures slowly close, forcing the mud with gas to flow back into the hole. When the drilling fluid circulates to the surface, it registers as an increase in total gas. However, on the chromatograph, it is characterized by an increase in C₁ and C₂ gases, with little change in C₃, C₄ and C₅ gases.

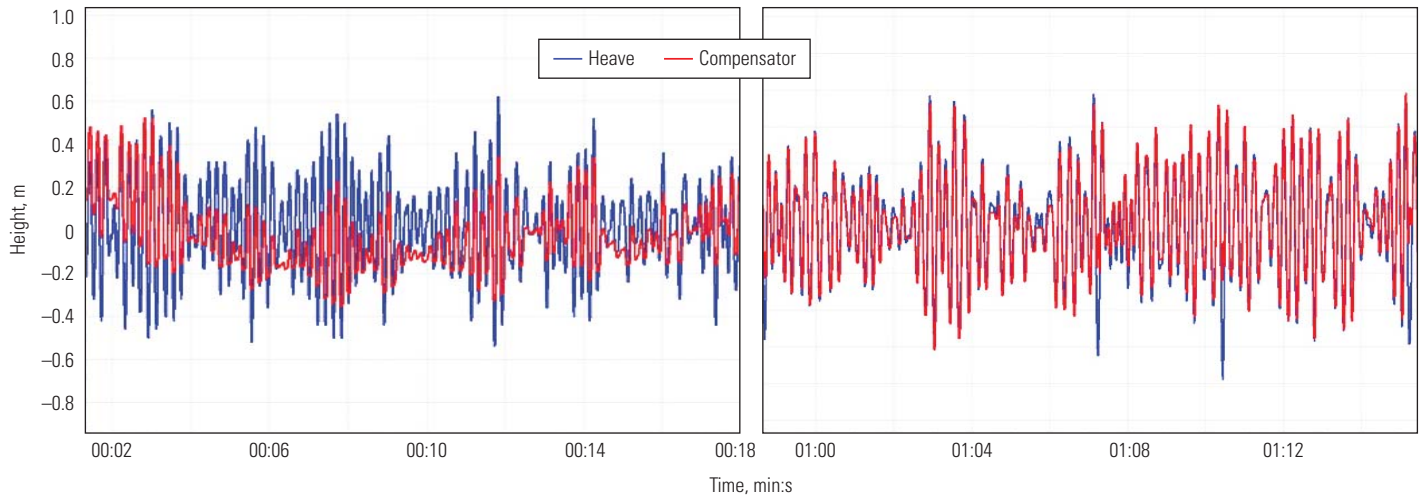
To maintain mud weight within the narrow pressure window, managed pressure drilling (MPD) techniques were used for early kick detection, maintaining constant bottomhole pressure control and conducting dynamic flow checks and dynamic formation integrity tests (FITs).²³ When engineers compared the VSP look-ahead pore pressure curves with actual pressure readings from an MDT modular formation dynamics tester and StethoScope formation pressure-while-drilling tool, they found that the readings closely matched each other (left). After TD was reached, the wellbore was displaced with kill mud and the well was completed successfully.

Thema drilling operations support and analysis service—The Thema service processes real-time, high-frequency data streams from a number of sensors around the rig to provide up-to-date analysis of hole condition, drilling efficiency, well pressure balance and rig performance. This information is displayed on customizable screens installed at the logging unit and the company representative's workspace; it can also be accessed remotely from the operator's offices.

In hole condition mode, Thema engineers analyze wellbore stability and hole cleaning efficiency in real time. The drillstring weight is recorded while it is static, rotating or reciprocating. This program can also process input from cuttings flowmeters. Data are presented in depth or time, enabling the user to rapidly establish a sequence and correlation between events. These



Final composite log. Look-ahead estimates of pore pressure from VSP analyses are confirmed by actual pressure readings from MDT and StethoScope tools. Mud weight was kept as low as possible to keep the ECD from exceeding the fracture strength of the rock. In spite of this effort, some mud losses were experienced. The plots show that mud pressures (red) were maintained close to the estimated pore pressures.



▲ Heave versus compensation. Using Thema service data, Geoservices personnel tracked a drillstring vibration problem on a well in the Campos basin off the coast of Brazil. A comparison between the magnitude of heave and compensation (*left*) showed deficiency in heave damping, which was subsequently corrected (*right*).

data are analyzed to derive industry-standard values for torque, ECD, pickup, slack-off and free-rotating weights.

The drilling efficiency mode evaluates various drilling parameters to assess bit behavior and wear. Surface sensors monitor the frequency and magnitude of axial vibration caused by bit bouncing and stick-slip torsional vibrations. These inputs are used to anticipate potential problems such as bit balling, drillstring vibration and bit wear to optimize drilling parameters. The drilling efficiency mode may help improve ROP and increase the life of down-hole and surface equipment.

The Thema service helped one operator in the Middle East enhance core recovery in a formation susceptible to breakage. Breaks in core cause two main problems. First, the operator has difficulty in recovering representative samples of the formation. Second, broken core causes gaps in the core recovery footage count, which can severely degrade the quality of interpretation of any core that is eventually recovered.

Analysis of drilling sensor data from the first coring run revealed the core was being subjected to severe torsional vibrations inside the core barrel, resulting in a poor-quality core with many breaks and fractures. During a subsequent coring operation, the Thema service was used to manage drilling parameters and minimize drillstring vibration. The operator obtained a clean, unbroken core, thus validating the Thema analysis and recommendations.

23. For more on managed pressure drilling: Elliott D, Montilva J, Francis P, Reitsma D, Shelton J and Roes V: "Managed Pressure Drilling Erases the Lines," *Oilfield Review* 23, no. 1 (Spring 2011): 14–23.

To monitor rig performance, the Thema service automatically tracks and displays a specific combination of parameters, such as connection time or net drilling time per stand. The duration of each activity is logged, enabling assessment of the rig performance during various operations such as drilling, sliding, tripping and circulating. The wellsite data specialists work with Thema engineers at the operator's office to provide timely updates to rig site and office project members.

The Thema service was recently called on to determine the cause of poor drilling rates in wells off the coast of Brazil. During a three-year drilling campaign, the operator utilized Geoservices mud logging and Thema services on several wells drilled from semisubmersible rigs in the Campos basin. While most of these wells were drilled and completed on schedule, a few were taking longer than expected to reach TD, owing to dramatic decreases in ROP.

In contrast to neighboring wells with ROPs averaging 40 m/h [130 ft/h], some wells attained only 16 m/h [52 ft/h]—a 60% reduction. An evaluation of drilling performance indicated that ROP was hampered by vibration. However, the driller was unable to identify the exact cause of the problem.

On one well, the Thema service was used to record responses of various drilling performance sensors located around the rig. The Thema system acquires data at up to 50 Hz, enabling rapid correlation of sensor responses to various drilling parameters. Among the inputs were data from sensors to detect motion on the riser tensioner, heave compensator and topdrive block.

Analysis of sensor data helped Geoservices personnel track the problem to its root cause: Drilling energy was being dissipated through shock and torsional resistance as a result of heave motion (*above*). As is typical of semisubmersibles, the rig used heave compensators to reduce vertical drillstring movement caused by the rise and fall of ocean waves.

By fine-tuning the damping motion of the heave compensator, the drilling contractor was able to mitigate the problem and boost ROP while reducing stress on the drillstring. The ROP increased from 16 m/h to 45 m/h [148 ft/h]—exceeding the 40-m/h average of neighboring wells by more than 10%. These results prompted the operator to implement the same monitoring and mitigation practices on the five rigs the company employed in the area. In light of these results, the operator plans to use the Thema service in future wells.

The scope of services offered by mud logging companies continues to expand as new sensors and analytical tools are developed. In response, the mud logger has taken on an important role in providing the operator and drilling crew with information that is crucial to the success of the well and to the safety of the rig. In addition to formation evaluation experts, the mud logging unit must now accommodate specialists who are responsible for drilling efficiency and well safety. By linking a wide array of surface sensors to rapid analytical capabilities and operational expertise, the mud logging unit is fast becoming the nerve center of the drilling rig.

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