The Nuts and Bolts of Well Testing

During a field's exploration and appraisal phases and throughout its productive testing hardware has been developed over the years. Yet the demands made on

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Well testing is a dynamic process. At its simplest, a test discovers if a formation can flow and permits sampling of the produced fluid. Analysis can yield further information like the extent of formation damage near the borehole, reservoir permeability and heterogeneity, and initial productivity index. For this, engineers induce pressure transients by changing the rate that formation fluids enter the borehole and recording the resulting downhole pressure versus time. Transient tests can also reveal the reservoir's areal extent and vertical layering (see “Testing Design and Analysis,” page 28).

Testing hardware has to perform a range of tasks. First, the formation being tested must flow. If the well has not already been completed, it needs to be temporarily completed—that is, to have a packer set above the test zone to isolate it from the wellbore fluid's hydrostatic pressure.

To induce pressure transients, the engineer needs to control the well. The easiest method is surface shut-in. But during pressure buildup, the column of fluid between the point of shut-in and the formation has to be compressed by inflowing formation fluid—the so-called wellbore storage effect. Data analysis usually requires that pressure be recorded until wellbore storage no longer dominates.

When the wellbore volume is large (as in deep or horizontal wells) or the wellbore fluids highly compressible (as in gas wells), the wellbore storage effect can last a prohibitively long time. One way to minimize wellbore storage places a test valve downhole, as close as possible to the formation. Pressure gauges must be located below this test valve.

Data gathering is not an exclusively downhole activity. On surface, after the fluid has been controlled and separated, flow rate can be measured. Taking a sample of the produced fluid is also important. Detailed analysis of samples not only sheds light on the composition of the produced fluid but also offers insight into the reservoir itself. The dynamic performance of a reservoir is both a function of the formation and the formation fluid.

This article reviews the complex array of testing hardware now available. It examines how highly accurate pressure data is gathered downhole and how, on surface, flow rate is safely measured and samples are captured (next page).
life, well testing remains a vital activity. Increasingly sophisticated testing hardware remain unchanged.

**Downhole Hardware**

*Openhole Testing*—The first tests were conducted in open hole with the tools conveyed into the well on drillpipe—openhole drillstem tests (DSTs). While the earliest DST hardware dates back to the Johnston tools of the 1920s (see “The Birth of Downhole Test Hardware,” page 21), the modern era of testing really started in the 1950s. Then, multiflow evaluation tools were introduced, making possible repeated flow and shut-in cycles rather than the single flow and buildup offered before.

Today, multiflow evaluation tools are still used in the majority of openhole DSTs. If hydrocarbons are detected in either cores or cuttings during drilling or indicated by logs, a DST may be used to rapidly assess the production potential of the formation. Drilling information or a wireline caliper log are used to locate a suitable packer seat—a section of openhole that is in gauge and

In this article, COMPUTEST (Centralized Acquisition System), CQG (Combinable Quartz Gauge), DataLatch, IRIS (Intelligent Remote Implementation System), MDT (Modular Formation Dynamics Tester) and SPG (Sapphire Pressure Gauge) are marks of Schlumberger.

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Testing a cased well. A test valve and pressure gauges downhole are combined with surface separation and flow measurement equipment to gather formation drawdown and buildup pressure and flow rate data. Samples of formation fluid are taken at surface for analysis.
The packer is traditionally a solid unit of rubber that expands when some of the weight of the string is set down onto the anchor. The test valve is also opened and closed by setting down and picking up on the string. Therefore, to ensure that pipe manipulation does not unset the packer, a tool above it hydraulically maintains the downward force. The packer can be unset only by an extended pull for several minutes. After the test has been completed and the test string pulled out of hole, drilling continues and the process can be repeated on subsequent hydrocarbon shows.

If drilling is not halted when a potential hydrocarbon-bearing zone is encountered, an alternative test method is to wait until the well is drilled to total depth and then use straddle packers to isolate the zone of interest. The recent introduction of inflatable packers has made it possible to more effectively isolate and test individual zones pinpointed using wireline logs.

Cased-Hole Testing—The primary selling point of the early test tools was the avoidance of unnecessary casing costs. This has now largely been supplanted by the need for more data over a longer duration. Openhole DSTs gather important early information, but in many cases reservoir engineers need greater detail.

The extent of reservoir investigated is often proportional to test duration. A key factor governing the length of time an openhole test can be conducted is wellbore stability. At some point the well may cave in on top of the packer and stick the string downhole. Clearly, the hazards of wellbore stability are eliminated by testing after casings have been set. In many sectors, particularly offshore, cased-hole testing has all but replaced traditional openhole DSTs.

On land and from fixed platforms, openhole DST tools function effectively in cased wells by using a different type of packer that grips the casing rather than relying on bottomhole support. But as offshore drilling increased, floating rigs became common, and vessel heave could incidently cycle traditional weight-set tools and even unset the packer. Also, offshore developments tend to employ deviated wells, and the higher the well angle, the harder reciprocal tools are to control. New testing technology was required to ensure safe operations.

In the 1970s, cased-hole testing systems were introduced that exploit annular pressure to control and activate downhole tools. These eliminate the need for further pipe manipulation during the test once the packer is set. The new hardware increased the number of tests made from floating rigs and through its improved safety also found application on land and fixed platforms.

The downhole valve of the pressure controlled test string opens when pressure above a certain threshold—usually 1000 to 1500 psi—is applied on the annulus and closes when this pressure is bled off. It uses the same annular pressure threshold, regardless of depth, hydrostatic pressure and temperature. To do this, a chamber in the tool is precharged at surface with nitrogen. A compensating piston ensures that the nitrogen acquires hydrostatic pressure as the tool is run in hole.

Although these systems rapidly gained wide acceptance, it soon became apparent that in a number of cases significant advan-

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tages would accrue if wireline tools or coiled tubing could be run inside the test string, through the downhole test valve, to the producing zone. This became possible in the late 1970s when fullbore pressure-controlled test equipment was introduced with a minimum inside diameter of 2½ in. throughout the string (previous page).

Thus, test strings now offer the benefits of downhole shut-in while retaining access to the perforations for standard wireline-conveyed equipment with an outside diameter up to 2 in. This makes possible operations like perforating, downhole sampling and placing/recouping gauges during testing. It also clears the way for downhole flow rate measurement during the drawdown using production logging tools. Flow measurement during testing is proving to be valuable when testing layered reservoirs and horizontal wells. Analysis of downhole flow during drawdown is also helping to reduce test duration. A further advantage of a fullbore string is that the larger diameter minimizes plugging and reduces restriction to flow, crucial when large-volume stimulation is performed through the test string.

In addition to downhole shut-in, reverse circulation is an important phase of testing operations. This requires communication between the inside of the test string and the annulus just above the test valve. Mud can then be pumped down the annulus to flush out formation fluid left in the string. Opening a reverse circulation valve also allows the string to be pulled dry—fluid drains out of the tubing downhole as the test string is pulled out of the well.

Openhole DST strings and the first pressure-controlled testers usually included circulation valves activated by dropping a bar or rupturing pressure disks, usable only once and not recloseable. Another advance associated with fullbore strings was the introduction of circulation valves that could be opened and closed repeatedly. These can be used to place fluids inside the string, above the test valve.

For example, to control the rate at which formation fluid starts flowing once the test valve is opened, a column of fluid with a carefully controlled hydrostatic pressure is often put inside the string—called the cushion. This can be conveniently circulated into place using a multiple-operation circulation valve. The valves are also used to remove flammable wellbore fluids before pulling the string and perform well cleanup operations where heavy fluid preventing flow is circulated out of the well (below).

Further refinement comes with the use of tubing-conveyed perforation (TCP) guns along with a pressure-operated test string. This significantly cuts the rig time—and therefore the cost—needed to shoot and test, particularly for long intervals. But the main advantage is that perforation can be carried out underbalanced—when the hydrostatic pressure of fluid above the zone of interest prior to firing the guns is less than the anticipated formation pressure. This minimizes invasion of the formation by wellbore fluid that normally occurs when wireline perforation guns are used. The initial surge of formation fluid after firing TCP guns also

Reverse circulation. Produced fluids sometimes create too high a hydrostatic pressure to flow to surface, killing the well—often the case where invaded mud or spent stimulation fluid are produced with the reservoir fluids. The multiple-operation circulation valve enables these heavy fluids to be reversed out and replaced by a lighter one—usually diesel oil or fluid-energized nitrogen. In this way the formation can be cleaned out, allowing it to flow freely.
flushes out charge debris and crushed formation from the perforation channel.2

Increased sophistication in testing demands additional tools, for example an extra shut-in valve that, as a safety precaution, can cut wireline, a single-shot reversing valve and a downhole sampler. Like the fullbore test valve, and often the multiple-operation reversing valve, all these tools are annular-pressure operated, creating the need for a complex sequence of distinguishable pressure pulses (left).

The annular pressure has to supply not only a discrete signal to one of a number of tools, but also the power to operate it. For example, opening the single-shot reversing valve at the end of a test can typically require 2000 to 3000 psi above the hydrostatic pressure. This creates significantly high pressures in the annulus, and great care has to be taken not to exceed the collapse pressure of the tubing—in which pressure is deliberately kept to a minimum to encourage the formation flow—nor the burst pressure of the casing.

There is a limit to the number of discrete annular pressure signals that can be safely employed to command and power downhole equipment. A recent development—the (IRIS) Intelligent Remote Implementation System dual-valve tool—addresses this by employing much lower annular pressure variations as command signals to the downhole tools. The signals are analyzed by the tool’s controller, which uses electronics to control the downhole test valve and circulating valve. Batteries power the electronics; annular hydrostatic pressure supplies the energy to operate the valves.

Whereas a traditional pressure-operated tool might require commands of up to 3000 psi above hydrostatic, IRIS responds to pulses of about one-tenth of that, making it immune to casing and tubing limits. The low-intensity coded pulses of at least 250 psi are sent down the annulus using rig mud pumps. The key recognition factor for the IRIS system’s pressure sensor is the shape of the pressure pulse. A threshold pressure has to be achieved, sustained and bled off within specific time and pressure variation constraints. The duration that a plateau pressure is sustained distinguishes one command from another (next page, top left).

In the tool, a microprocessor reads the coded pressure pulses, compares them to preset operating instructions and opens or closes solenoid valves to direct hydraulic fluid from chambers at annular hydrostatic pressure into chambers at atmospheric pressure. This fluid movement is used to operate the tool’s valves—closing them with a high

[Keeping track of pressures during a test. Three pressure-controlled tools are used in this test that also includes an acid stimulation job. The test valve requires 1500 psi applied annular pressure to open it and closes when this pressure is bled off. The multiple-operation reversing valve is opened by tubing pressure and closed by pumping through the tool into the annulus at sufficient rate to create a pressure drop. This pressure differential is harnessed to mechanically reseal the annulus from the tubing. The one-shot reversing valve is opened at the end of the job by 2500 psi annular pressure.]

<table>
<thead>
<tr>
<th>RIH</th>
<th>Open/ close test valve</th>
<th>Open/ close test valve</th>
<th>Open circulating valve, reverse out</th>
<th>Spot acid</th>
<th>Open test valve, pump acid, close test valve</th>
<th>Open reversing valve, reverse out</th>
</tr>
</thead>
</table>

| Annular pressure applied to open test valve | Annular pressure released to close test valve | Cushion and formation fluid reversed out | 2500 psi applied to open one-shot reversing valve and reverse out string contents |

| Tubing pressure | Test valve closed, pressure applied to tubing to open circulation valve | After acid is spotted, the circulation valve is closed | Test valve opened and acid injected into the formation |

| Pressure below test valve | Test valve opened, the well flowed and tubing pressure increased at surface | When the reversing valve was opened, pressure was seen briefly below the test valve | Acid job |

| Initial hydrostatic | First flow | First shut-in | Second flow | Second shut-in | Final hydrostatic |

18 Oilfield Review
Feeling the pulses. Pressure pulses controlling the IRIS dual valve have to build up to a preset value within a given length of time, be maintained within a preset tolerance and then bled off within a set period of time. The duration the pressure is maintained is a key factor distinguishing one signal from another. The pulses are generated using the rig’s mud pumps and standard drillers’ controls.

Cycling the IRIS dual valve tool. Low-pressure pulses in the annulus are interpreted by a downhole controller to activate servo valves that direct the flow of hydraulic fluid. This fluid, moving from one chamber at hydrostatic pressure into another at atmospheric pressure, powers the opening and closing of the test and circulation valves.

Annular pressure pulses needed to control the IRIS dual valve tool in conjunction with either pressure- or drop-bar-operated TCP strings.

Test valve opens sequential mode enabled
Circulating valve opens
TCP guns fired using annular pressure
TCP guns fired using drop bar
Test valve closes
Main flow period
Drop bar TCP guns fire
TCP guns fire

Test valve opens
Circulating valve opens

Test valve closes

Apply annular pressure

- 1200
- 1000
- 800
- 600
- 400
- 200
- 0

- 1200
- 1000
- 800
- 600
- 400
- 200
- 0

- 1200
- 1000
- 800
- 600
- 400
- 200
- 0

- 1200
- 1000
- 800
- 600
- 400
- 200
- 0

Commands

- dt1, dt2 min
- 0.5
- 1.0
- 2.0
- 2.5

Commands

- dt1, dt2 min
- 0.5
- 1.0
- 2.0
- 2.5

Intensity force driven by the differential pressure rather than by just the force of a spring, as in conventional systems. Because clean hydraulic fluid is operating the tools rather than mud, reliability is also enhanced (right).

Since the tool functions through electro-hydraulics, its mechanical construction is simplified. The 20-ft [6-m] IRIS dual valve tool replaces conventional fullbore test strings measuring some 40-ft [12-m] long. Elimination of pressurized nitrogen chambers also removes a potential safety hazard. The equipment is compatible with conventional pressure operated test equipment. It can also be used in conjunction with TCP—either drop bar or pressure activated (top, right).

Although the valves can be opened or closed by sets of double pulses, an alternative is to use what is called sequential mode. Once the tool has been opened by a single pressure pulse, 200 psi has to be maintained on the annulus to keep the test valve open. It closes immediately if this pressure is bled off. It also closes if pressure is increased above a maximum. This is analogous to the mode of operation of previous generation, pressure-operated tools. Reopening the test valve requires two pulses of the correct duration (next page).


Testing in Permanent Completions—All test equipment described so far is for use in temporary completions. Testing in permanently completed wells falls into two categories. The first is a variation of temporary completion tests. The second occurs during the productive life of a well.

If a test will last longer than a few days, is likely to encounter high temperatures and pressures or if company safety policy dictates, a permanent rather than retrievable packer is preferred. A production wellhead is also usually used rather than a temporary flow head. The rest of the hardware is usually the same as that previously described.

The second category occurs later in a well’s life. Today, this mostly involves shutting in the well at surface or simply changing the choke size, and therefore flow rate. However, in some cases downhole shut-in is achieved using valves that are run into a well on wireline and hung in nipples in the production tubing. Valves are opened or closed using either wireline manipulation or downhole battery power. These downhole valves were developed for exactly the same reason as DST valves: reservoir engineers wanted to minimize interference from wellbore storage effects.

Wireline-operated valves are opened and closed by reciprocating the monoconductor cable. Pressure is read out at surface (next page, middle). Some tools can perform production logging during the flow period.

A battery-operated valve can be hung off and left in the well. After a preset flow period, it closes permanently for a buildup. This type of valve is generally used for long-term tests, with buildup lasting weeks—often as part of interference tests where pressure is monitored during drawdown from an adjacent well.

Collecting Downhole Data

Pressure Gauges—No matter how efficiently the mechanical aspects of a test have been executed, whether using an openhole or cased-hole DST string, it will have failed if pressure data are inadequate for analysis.

During tests, pressure and temperature data are measured and stored in downhole recorders that comprise three sections: gauges, power source and memory. In general, two to four recorders are used for redundance and to enable comparison of

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**Table of Operations**

<table>
<thead>
<tr>
<th>Date</th>
<th>Operation Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>November 5, 1991</td>
<td>Run in hole</td>
</tr>
<tr>
<td>November 6, 1991</td>
<td>Open well at surface</td>
</tr>
<tr>
<td>November 7, 1991</td>
<td>Shut in well at surface</td>
</tr>
<tr>
<td>November 8, 1991</td>
<td>Open well at surface</td>
</tr>
<tr>
<td>November 8, 1991</td>
<td>Change choke at surface</td>
</tr>
<tr>
<td>November 8, 1991</td>
<td>Shut in well at surface</td>
</tr>
<tr>
<td>November 8, 1991</td>
<td>Bleed down annulus to SM. Close TV, below TV pressure builds up while tubing bleeds down</td>
</tr>
<tr>
<td>November 8, 1991</td>
<td>Pressure up annulus to open TV using SM. Repeat several SM operations to open/close TV</td>
</tr>
<tr>
<td>November 8, 1991</td>
<td>While well is open in SM, pressure up annulus to check SM overpressure shutdown works. TV shuts and disables SM simultaneously</td>
</tr>
<tr>
<td>November 8, 1991</td>
<td>Open circulating valve on a dry string</td>
</tr>
<tr>
<td>November 8, 1991</td>
<td>Close CV (two pulses)</td>
</tr>
<tr>
<td>November 8, 1991</td>
<td>Open TV (two pulses)</td>
</tr>
<tr>
<td>November 8, 1991</td>
<td>Disable SM, TV is ‘locked’ open using single short pulse</td>
</tr>
<tr>
<td>November 8, 1991</td>
<td>Unseat packer, circulate through string below packer with TV open</td>
</tr>
</tbody>
</table>

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**Key**
- CV – Circulating valve
- TV – Test valve
- SM – Sequential mode

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**Graph**
- Downhole annular pressure
- Below test valve pressure
- Tubing pressure
- Surface annular pressure

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**IRIS dual-valve tool in action. Pressure details from a test carried out by AGIP in the Adriatic Sea, offshore Italy. The time axis is not to scale.**
The cost of these gauges increases from the least expensive mechanical to most expensive quartz gauges. In most cases, quality of data improves with cost. When deciding which gauge to deploy, the engineer has to know how measurement error may affect the subsequent data analysis. The two key measures of gauge performance are stability and resolution. Gauge stability is indicated by its drift—the change in output value over time that is not a function of the measured pressure. Resolution is the smallest change in pressure that leads to a measurable change in a gauge's output (expressed either as a percentage of full scale or as psi). The performance of some of the available gauges is summarized in “Comparison of Pressure Gauge Performance,” next page. Because of their relatively low accuracy and resolution, use of mechanical gauges is gradually diminishing, particularly when advanced analysis techniques are employed.

(continued on page 24)
## Comparison of Pressure Gauge Performance

<table>
<thead>
<tr>
<th>Advantages</th>
<th>Mechanical gauge</th>
<th>Vacuum Shear mode</th>
<th>Capacitive gauge</th>
<th>Standard quartz gauge</th>
<th>Combinable quartz gauge</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Reliable</td>
<td>• Reliable</td>
<td>• Better resolution</td>
<td>• Higher resolution</td>
<td>• Higher resolution</td>
<td></td>
</tr>
<tr>
<td>• Rugged</td>
<td>• Rugged</td>
<td>• Fast response</td>
<td>• Lower accuracy</td>
<td>• Lower power</td>
<td></td>
</tr>
<tr>
<td>• Simple</td>
<td>• Simple</td>
<td>• Rugged and small</td>
<td>• Reliable and rugged</td>
<td>• Reliable and rugged</td>
<td></td>
</tr>
<tr>
<td>• Poor resolution, accuracy, stability, and dynamic response</td>
<td>• Medium stability, resolution and accuracy</td>
<td>• Medium stability</td>
<td>• Slower sampling</td>
<td>• Higher stability</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Temperature sensitive</td>
<td>• Temperature and vibration sensitive</td>
<td>• Higher accuracy</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• Pressure hysteresis</td>
<td>• More electronics</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Maximum range</th>
<th>20,000 psi 200°C</th>
<th>20,000 psi 175°C</th>
<th>17,000 psi 175°C</th>
<th>15,000 psi 175°C</th>
<th>11,000 psi 175°C</th>
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<table>
<thead>
<tr>
<th>Resolution</th>
<th>0.05% of full scale</th>
<th>0.2 psi (15,000 psi; 1-sec sampling)</th>
<th>0.1 psi (20,000 psi; 1-sec sampling)</th>
<th>0.01 psi (10,000 psi; 1-sec sampling)</th>
<th>0.001 psi (12,000 psi; 1-sec sampling)</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Accuracy</th>
<th>40 psi</th>
<th>15 psi</th>
<th>6 psi</th>
<th>&gt;12 psi</th>
<th>± [0.025% of reading + 0.5 psi]</th>
</tr>
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</table>

<table>
<thead>
<tr>
<th>Drift</th>
<th>~10 psi 1st day then</th>
<th>&lt;3 psi 1st day, then</th>
<th>&lt;3 psi 1st day, then</th>
<th>±1.4 psi/week (10,000 psi; 150°C)</th>
<th>± 0.2 psi in 18 days then</th>
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</thead>
</table>

<table>
<thead>
<tr>
<th>Drift</th>
<th>1000 psi step @ 150°C (gage rating)</th>
<th>&lt;1.5 psi/week (10,000 psi; 150°C)</th>
<th>&lt;1.4 psi/week (10,000 psi; 150°C)</th>
<th>± 0.2 psi in 18 days then &lt; 0.1 psi/week (10,000 psi; 120°C)</th>
<th>± 0.2 psi in 7 days then &lt; 0.1 psi/week (10,000 psi; 150°C)</th>
</tr>
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</table>

<table>
<thead>
<tr>
<th>Stabilization time</th>
<th>5000 psi step 10°C step</th>
<th>30 sec</th>
<th>~20 sec</th>
<th>8 min</th>
<th>6 min</th>
<th>Always within 1 psi</th>
</tr>
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<tbody>
<tr>
<td></td>
<td>10 min</td>
<td>10 min</td>
<td>10 min</td>
<td>40 min</td>
<td>25 min</td>
<td>25 sec</td>
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<table>
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<tr>
<th>Relative cost</th>
<th>Low</th>
<th>Medium</th>
<th>Medium</th>
<th>Medium</th>
<th>High</th>
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<table>
<thead>
<tr>
<th>Notes</th>
<th>Note 1</th>
<th>Note 2</th>
<th>Note 2</th>
<th>Note 2</th>
<th>Note 2</th>
</tr>
</thead>
</table>

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Note 1: These are estimated figures based upon published literature and manufacturers’ commercial data.

Note 2: These figures are based upon Schlumberger laboratory and field test data.
Gauges Through the Ages

Just as the downhole test valve has evolved since its genesis in the 1930s, so pressure gauges have advanced. Initially, there were clock-driven mechanical gauges. Then electronic recorders with strain gauges, capacitance transducers and quartz gauges became available.

Most mechanical gauges use a Bourdon tube to convert pressure variation into mechanical movement. This movement is linked to a stylus that scratches lines on a cylinder of coated brass foil—similar to the first Edison phonograph. A mechanical clock rotates the cylinder and thus provides a pressure versus time chart. Although primitive, mechanical gauges are still used and have a resolution of 1 to 5 psi for a 10,000-psi gauge.

Electronic gauges couple the pressure-sensing element to a transducer that converts stress and strain into some form of electrical signal. Just about the simplest such technique employs strain-sensitive resistors on a metal membrane. As these undergo displacement, their geometry, and therefore resistance, changes creating an analogous electrical signal. Advantages of the strain gauge are many: they are simple, robust, small, fast and reliable. However, resolution—and ultimately stability—is limited by the physical characteristics of the metal used for the strain gauge to about 0.2 psi for a 15,000-psi gauge.

The limitation of the simple strain gauge is its metal membrane. Metals are inherently made up of loosely interlocking microscopic crystals that cause the gauge never to return to exactly the same state after being subjected to pressure—a condition called hysteresis. To improve this response, a better substrate was required.

This line of reasoning led to the development of the recently introduced SPG Sapphire Pressure Gauge. In this, a miniature capsule, or box, of sapphire crystal is constructed with a vacuum inside. To measure pressure, a strain gauge bridge circuit is deposited as a thin film onto the surface of the crystal. Its operation follows the same principle as conventional strain gauges: pressure distorts and changes the resistivity of the circuit on the sapphire’s surface and the electrical signal is altered. Temperature is also measured using a thin-film sensor mounted on the same crystal.

The SPG gauge’s resolution is similar to that of conventional strain gauges (0.1 psi for a 10,000-psi gauge), but its dynamic response and stability are much improved. This is because rather than having a membrane of interlocking and creeping crystals, it comprises a single crystal which, when pressure is reduced, returns to its original state.

Another family of sensors are capacitance transducers. Typically, two plates separated by a gap are coated with conductive material. As the pressure changes, the distance between the two plates and therefore the capacitance changes. Difficulties with these gauges include measuring the minute changes in capacitance and a sensitivity to temperature. To achieve the desired signal-to-noise ratio, the surface areas of the plates have to be relatively large. This makes them prone to transient variations under dynamic conditions. Mechanical vibrations and metallurgical effects can also upset the pressure reading. Furthermore, the two plates’ position relative to gravity can affect the minute distance between them, making these gauges sensitive to orientation.

The most accurate pressure sensors use quartz crystals. A correctly cut section of quartz has a natural or resonant frequency of vibration—like a tuning fork. As the quartz vibrates, there is a detectable sinusoidal variation in electrical charge on its surface. Pressure-induced stress applied to the crystal causes the sine wave’s frequency to vary in a very precise manner.

Unfortunately, the pressure sensitivity of the resonator is low—about 1.5 Hz per psi—compared with its temperature sensitivity—about 15 Hz per °C. To correct for this susceptibility to temperature variations, two approaches have been employed. In one, an accurate thermometer is used to calibrate the pressure calculation. However, the thermal time lag between the quartz and its thermometer compromises the measurement.

The other approach employs a second, reference quartz crystal that exhibits similar temperature behavior as the pressure transducer. By installing it in a vacuum chamber isolated from changes in pressure, it responds only to temperature. The frequency outputs of the two crystals are then subtracted to give a beat frequency that is mainly a function of the pressure.

However, this transducer also has problems coping with changes in temperature because of a thermal time lag between the two crystals. In dynamic conditions, this type of gauge takes 30 minutes to an hour to reach equilibrium, creating an error in the order of 1 to 10 psi for a 10,000-psi gauge.

The latest development, therefore, has been to measure temperature and pressure simultaneously within the same crystal in a single quartz transducer. In the CQG Combilable Quartz Gauge, two vibration modes at offset angles are excited on a single quartz resonator plate. One mode is particularly sensitive to temperature and is used as a thermometer to correct the frequency-temperature behavior of the other more pressure-sensitive mode. Because this happens on the same piece of quartz, there is no possibility of a temperature lag or discrepancy.

The CQG transducer consists of a quartz crystal comprising a body and two end caps. The dual-mode resonator is a plate inside the body in a vacuum maintained by the end caps. Pressure outside the transducer induces stress inside the resonator, which changes resonant frequency.

Tests on the CQG gauges have shown it has an accuracy of 1 psi over a range from atmospheric pressure to 15,000 psi at temperatures 35°C to 175°C (95°F to 350 °F). Response to changes in temperature is extremely fast—less than a few seconds—rather than the 30 minutes or so taken by previous quartz gauges.1

Independent downhole shut-in with surface pressure readout. When used in combination, the valve assembly is run in hole with the string above the test valve. An actuator that includes a pressure gauge assembly is run on monoconductor wireline and latched into the valve assembly. Once latched, a flapper valve can be opened and closed simply by picking up and slacking off on the wireline. Pressure below the valve is continuously monitored by a surface computer system that communicates with the gauge via the wireline. The tool can be used for up to 12 preset flow and shut-in cycles. After a preset number of manipulations, the tool is released and retrieved.

However, mechanical gauges are simple, rugged and still the only instruments capable of withstanding bottomhole temperatures in excess of 200 °C [415 °F].

Electronic strain gauges perform much better than mechanical gauges but they are affected by significant drift, particularly during the first day downhole.

Another factor is how quickly a gauge stabilizes after a rapid change in temperature and pressure. The stabilization time is usually defined as the time needed to come within 1 psi of the actual pressure. Standard quartz gauges are very precise, but usually take up to 30 minutes to stabilize after large temperature or pressure changes—30°C or 1000 psi. The new CQG Combinable Quartz Gauge stabilizes virtually instantaneously because it measures both the temperature and pressure within the same quartz crystal.

Finally, when TCP is to be employed, the gauges have to be capable of withstanding the explosive shock.

The power source of mechanical gauges is clockwork. Most other types of gauge are powered by batteries which must survive the anticipated downhole temperature—few currently exceed a working temperature of 175 °C [350°F].

The gauge memory stores the pressure and temperature data and needs to be of sufficient capacity to last the anticipated duration of the test. Sometimes, data-compression algorithms are employed to ensure that valuable memory is conserved. A further requirement is for the downhole recorder to retain its memory after the batteries are dead.

Another important element is packaging. In the beginning, mechanical gauges were installed in carriers below the downhole...
Keeping your options open. The DataLatch system comprises two main components: an inductive coupling section on top and a fullbore, multisensor recorder below. In this case, there is also a fullbore flow-control valve below the recorder.

The ability to read and reprogram the recorder offers the chance to alter data sampling rates and temporarily shut the tool down to save battery power.

The recorder batteries have a maximum life expectancy of about 500 hours. To best deploy its nonvolatile memory requires efficient organization of data. An algorithm is used to determine whether a new data point differs enough to merit storage.
Flow Measurement and Sampling on Surface

On surface, the fluids produced during a test are normally handled using temporary equipment that has to safely and reliably fulfill a wide range of operations:

- provide a means of quickly controlling the pressure and shutting in the well
- separate produced fluid into its gas, oil and water phases, allowing the constituents to be metered, and record key data like temperature and pressure
- allow samples to be taken
- dispose of the produced effluent in an environmentally acceptable manner.

Pressure Control—Traditional safety philosophy seeks to maintain a minimum of two independent barriers between the surface equipment and the formation. These may be located at three levels: downhole, subsurface and surface. Downhole barriers include the DST test valve itself or a special safety valve used only in emergencies.

Subsurface barriers are not universally employed on fixed rigs or onshore. In some cases, particularly high-pressure gas wells, an additional means of shutting in the well is required—analogous to subsurface safety valves used in permanent completions.

Any system deployed from a floating rig must offer rapid detachment of the string in the event of rough weather, loss of anchor or failure of the rig’s dynamic positioning system. To achieve this, a subsea safety valve assembly is landed inside the seafloor blowout preventers (BOPs). This provides a seabed valve to close the drillstring and allow disconnection. Once disconnected, the remainder of the string below seabed level hangs in a fluted hanger under the BOP (right).

Surface shutoff is usually provided by a flow control head which functions as a temporary christmas tree. The flowhead comprises four valves, the master valve, swab valve and two wing valves. The master valve is attached to the top of the test string which it isolates from the surface equipment. The swab valve allows introduction of wireline, slickline or coiled tubing. One wing valve allows fluid to flow out of the well; the other allows kill fluid to be pumped into the well (page 15).

The flowline valve is equipped with an automatic shutoff system driven by surface pressure monitors. If surface pressure exceeds a preset value or suddenly drops (indicating a failure of some part of the equipment at surface), the valve closes.

After the flow control head, comes the choke manifold that controls the produced fluid, imposing a constant flow rate. A choke is simply a restriction to flow, and the choke manifold usually contains two such restrictions—flow can be directed via either or through both in parallel. One of the chokes is usually variable, while the other incorporates inserts with calibrated diameters called flowbeans—it is important to know the exact diameter of the choke when making pressure and flow rate measurements.

The variable choke is used to gain quick control. Once flow rate is stable, a flowbean is used for the rest of the flow period. The aim is to impose critical flow across the...
choke. When this has been achieved, changes in pressure and rate made downstream from the choke, do not affect downhole pressure and flow rate.

Separation and Flow Rate Measurement—To accurately measure flow rate, the produced fluid has to be separated into oil, gas and water. Test separators tend to be adaptable, capable of handling all types of output: gas, gas condensate, light oil, heavy oil, foaming oil, water and spent stimulation fluids like acid. The possibility that hydrogen sulfide can be produced by any exploration well necessitates special equipment and enhanced safety precautions.

Gas often requires heating prior to separation to help prevent formation degradation. Hydrate inhibition through chemical injection is also sometimes necessary. Some oils, particularly viscous ones, require heating to improve separability.

Once the phases have been separated, their flow rates can be measured: liquid flow rate, using flowmeters; gas flow rate, using an orifice plate—where the absolute pressure and the pressure drop across an orifice are proportional to the mass flow rate.

Separated oil and condensate then pass into either a gauge tank, which vents to atmosphere via a flame arrester, or, when hydrogen sulfide is expected, a pressurized surge tank. In these, volume can also be measured to calibrate the flowmeters. Because the pressure of the oil is further reduced when it reaches this stage, additional gas can come out of solution, causing shrinkage, which can also be measured at the gauge or surge tanks.

Pressure, temperature and flow rate measurement at surface can be combined with downhole data using the COMPUTEST centralized acquisition system. This records all the data, and at the same time calculates and displays parameters in real time. Continuous remote sensing with automatic alarms reduces the exposure of personnel to risk and improves safety, particularly during high-pressure or harsh-environment testing. The data gathered by the system can be validated while the test is in progress using interpretation software, allowing the test procedure to be optimized in light of experience.

Sampling—Samples of gas, oil and water are always taken at surface from the test separator. Gas and liquid samples can then be recombined in the proportions indicated by the volumes of the separated phases measured at the separator. When the resulting mixture is subjected to reservoir conditions, it should be as close as possible to what is actually in the formation.

Once the sample has been obtained, it is the job of the PVT (pressure-volume-temperature) laboratory to conduct a thorough analysis. Resulting information can be split into two categories: physical and compositional. Physical information includes the pressure-volume relationship, oil volume factors (the volumes the oil occupies at reservoir and standard conditions) and viscosities. Compositional analysis includes chemical breakdown of the complex components in the sample. Water samples are analyzed to determine whether they are mud filtrate or formation water.

This information is essential not only in understanding the reservoir, but also in designing surface production facilities and maximizing recovery. For example, a crude oil might form wax at surface or have a high hydrogen sulfide content; the process equipment must be designed to take this into consideration.

However, prior to the PVT analysis, which may take weeks to deliver, some compositional data can be estimated at the wellsite during the test. Using gas chromatographic analysis of the fluid composition and an equation-of-state-based thermodynamic model, a number of parameters can be estimated, including bubblepoint at reservoir conditions, reservoir fluid specific gravity and volume factor at the bubblepoint and reservoir fluid conditions as a function of declining reservoir pressure.

If the flowing reservoir pressure is above the bubblepoint pressure, a monophasic downhole sample can be collected and brought to surface in a sealed container. In theory, this has been possible since the introduction of the first openhole DST systems. In these, a double-seal system traps a downhole formation fluid sample within the tool and brings it to surface with the string. Today, fullbore test systems all include tools to take samples.

However, the quality of samples acquired this way is greatly dependent on the reliability of the seals within the chamber as they are pulled out of hole. One does not know whether a sample has been successfully secured until the test string reaches the surface. And if the sampler has failed, it is too late to do anything about it.

Samples can also be taken during testing using wireline-conveyed samplers run in front of the perforations to trap a single-phase sample of the formation fluid. A further method of obtaining formation fluid samples comes through the use of wireline tools during openhole logging (see “The MDT Tool: A Wireline Testing Breakthrough,” page 58).

Disposal—As environmental constraints tighten, the acceptable disposal of produced fluid presents an increasing challenge. In general, gas and oil are burned. Onshore, this usually occurs in flare pits. Offshore, the primary concern is to avoid dropping oily or carboniferous residue into the sea. At first, offshore testing was hampered by the need to dispose of oil which had to be stored offshore or offloaded into a tanker. Then in the late 1960s, Flopetrol introduced the first flaring system to safely and efficiently burn oil, making possible economic offshore testing.

Within a typical burner, oil flows from the separator into a chamber where it is atomized by compressed air. The mixture is then ignited. Water sprayed into the flame creates high turbulence, improves the efficiency of the burning and prevents the formation of carbon black.

Water is usually produced in relatively small volumes that can be handled without problems using the rig wastewater system. —CF