In its simplest form, testing provides short-term production of reservoir fluids to the surface permitting the operator to confirm the show—indicated by cuttings, cores and logs—and estimate reservoir deliverability. In its subtlest form, measured pressure transients caused by abrupt changes in production can characterize completion damage, reservoir permeability and distant reservoir heterogeneities.

The logistics of well testing are simple in concept, but complex in practice. Flowing an exploration well requires a temporary completion. Flowing any well not connected to downstream facilities requires heavy surface equipment including separators and flares. Obtaining pressure transients requires alternately shutting and opening the well, preferably downhole, and making accurate downhole measurements of pressure. Increasingly, testing is performed in combination with perforating and production logging to measure downhole flow. They are routinely run in horizontal as well as vertical wells.

Developing the multifarious and intricate hardware to accomplish all these tasks is a design engineer’s dream. And juggling the many options for conducting a well test provides endless challenges in the field (see “The Nuts and Bolts of Well Testing,” page 14). This article concentrates not on hardware but on the information well tests give and how tests are designed and interpreted.

Primary concerns in testing exploration wells are obtaining representative samples and estimating reservoir producibility. Fluid samples are needed to determine various physical parameters required for well test analysis, such as compressibility and viscosity, and for pressure-volume-temperature (PVT) analysis that unlocks how the hydrocarbon phases coexist at different pressures and temperatures. For oil, a critical PVT parameter is bubblepoint pressure, the pressure above which oil is undersaturated in gas and below which gas within oil starts being released. Maintaining reservoir pressure above bubblepoint is key to successful testing since the principle of transient analysis, described below, holds only if flow in the reservoir remains monophasic. Estimating reservoir producibility requires achieving producibility by altering the production rate and noting changes in bottomhole pressure (top). A well’s productivity index, or inflow performance, is the slope of the straight line, measured in barrels of oil per day per psi. The straightline response curves downward once pressure falls below bubblepoint and gas starts coming out of solution.

In a layered reservoir, individual production rates measured using a production logging tool—layers A, B and C in this example—are plotted versus each layer’s wellbore potential, the wellbore pressure normalized to a datum. This so-called selective inflow performance technique reveals individual layer inflow performances and also pressure imbalances between layers that can promote crossflow.

In this article, COMPUTEST (wellsite computer system), FFE (Fluid Properties Estimation), IMPULSE (measurement while perforating), MDT (Modular Formation Dynamics Tester), PLT (Production Logging Tool), RFT (Repeat Formation Tester), SPG (Sapphire Pressure Gauge), STAR (Schlumberger Transient Analysis and Report) and ZODIAC (Zoned Dynamic Interpretation Analysis and Computation) are marks of Schlumberger.

ing stable flow rates at several choke sizes and then determining the productivity index from the slope of the flow versus drawdown pressure data (previous page).

The type of oil as determined by a sample and the ability of the well to produce are the first steps toward commercial exploitation. If well productivity is less than expected, then wellbore damage may be the cause. This is the next concern in testing exploration wells. Estimating the near-wellbore condition to perform necessary remedial action and ultimately to plan a well completion strategy for the field is accomplished from the transient analysis part of a well test.

Transient analysis, however, reaches deeper than just the near-wellbore region. Today, it contributes so much to characterizing the reservoir that engineers increasingly refer to well testing as reservoir testing. Analysis can indicate the likely producing mechanism of the formation—for example, how much production comes from fractures, how much from intergranular porosity—and it can determine the producing zone’s permeability-thickness product, \( kh \). It can see to the limits of the reservoir indicating the probable shape (but not orientation) of the reservoir boundaries and can show whether the primary recovery mechanism is from water or gas-cap support. This information becomes crucial in the appraisal and production stages of field development when engineers combine testing interpretation results with seismic and geologic data to refine their understanding of the reservoir.

How does transient pressure testing work? Imagine first an oil well in stable production with a certain pressure drawdown between the far limits of the reservoir and the well. Now shut in the well. In the formation, a sort of concertina effect takes place (below). Oil near the wellbore is the first to sense the shut-in and gets stopped in its tracks as it tries to push more oil ahead of it, getting compressed in the process. Then, the shock is felt farther away as news of the shut-in, so to speak, travels to the outer regions of the reservoir. Gradually, the pressure builds up everywhere, eventually reaching the reservoir pressure that drives production.

The reservoir engineer follows this chain of events by measuring the pressure buildup, or transient, and through analysis determines information about the reservoir from near the wellbore to its limits. An analogous chain of events occurs if instead of shutting in the well, the well is opened and allowed to flow. Again, it is oil near the wellbore that first senses the disturbance, but it is only a matter of time for oil deeper in the reservoir to respond and begin flowing too. Drawdown pressure measurements to track these events practically mirror the buildup response. In fact, transients can be obtained simply by increasing or decreasing the flow rate.

Transient testing depends on accurate pressure measurements taken long enough after the flow rate change to observe what the test was designed to detect. Impulse testing, for example, measures the transient that occurs as a well is perforated, allowed to produce for a short time and then shut in.
The primary target is the near-wellbore region (right).\textsuperscript{3} The goal is to assess formation damage and, if necessary, perform stimulation. Tests last just an hour or two. In a conventional test conducted to investigate reservoir boundaries, often called a limit test, the transient must be long enough for the pressure disturbance to reach the boundaries and then create a measurable response in the well. How long this takes depends on formation and fluid characteristics. In particular, the lower the formation permeability, the more time is needed—tests can continue for days. Longest lasting are interference tests, in which the effect of a transient created in one well is observed in another, yielding information about reservoir transmissivity and storativity.

The analysis and interpretation of well tests have evolved remarkably since the technique became established in the 1930s. Today, a unified methodology has developed to obtain the maximum information from any transient.\textsuperscript{4} The conventional test on a new well comprises two flow periods and two shut-ins (next page). The first flow period, perhaps an hour long, is designed to clean up the near-wellbore region and give the field crew time to manipulate chokes to establish a practical, stable flow rate. The well is then shut in and pressure builds up to reservoir pressure, an important parameter for the reservoir engineer. Then begins a long flow period, followed by a shut-in lasting at least 1.2 to 1.5 times as long. This last step generates the transient designed to yield the reservoir’s secrets. Of course, there are many variants on this theme (see “Textbook Well Test from the Congo,” page 33).

Three types of well testing: Impulse, conventional and interference. Impulse testing measures the transient caused by a very brief flow, typically just as the well is perforated. Results yield skin and permeability and may indicate if remedial stimulation is required. Conventional well testing measures the shut-in transient after a lengthy flow period and is often used to detect reservoir limits. Interference testing measures the transient in a well caused by one or more flow pulses in a nearby well. Results yield details about interwell transmissivity and storativity.

4. For a review:
   For the development of well test analysis:

The basic data obtained are change in pressure, $Dp$, versus elapsed time since the transient was initiated, $Dt$. In traditional analysis, $Dp$ is plotted against the logarithm of $(t_p +Dt)/Dt$, a dimensionless variable in which $t_p$ is the duration of the flow period. This is the Horner plot—$(t_p +Dt)/Dt$ is called Horner time (next page)—and the transient is analyzed by tracing the progress of the data from right to left.

First comes wellbore storage, which refers to the obfuscating role of the wellbore fluid when a transient is initiated. The moment a well is shut in or allowed to flow, fluids in the wellbore must first compress or expand before formation fluids can react. If flow is controlled from the surface, the entire well’s fluids contribute to wellbore storage and the effect can dominate the pressure transient for hours afterward. The effect is exacerbated if well pressure toward the top of the well drops below bubblepoint and part of the well is filled with compressible gas. Wellbore storage is substantially reduced by shutting in the well downhole, minimizing the volume of fluids that contribute.

As wellbore storage dissipates, the transient begins to move into the formation. Pressure continues building up, but at a slower rate as the transient moves far enough to achieve radial flow toward the wellbore. This is the so-called radial-flow regime that appears as a straight line trend on the Horner plot. The radial-flow regime is crucial to quantitative interpretation, since it provides values for $kh$ and skin, $S$, a mea-
A pressure transient breaks into several regimes on the log-log plot, each seeing deeper than the last. The first regime typically reflects wellbore storage, during which both the pressure and derivative curves overlay and increase along a straight line of unit slope. As wellbore fluids stabilize, pressure continues building up, but at a slower rate. The derivative curve swings down, eventually flattening out as the transient moves far enough from the wellbore to achieve radial flow. Since the radial-flow regime is a straight-line trend on the Horner plot, the derivative curve on the log-log plot is constant and traces a horizontal line. The interpreter’s first task always is to identify this derivative plateau, but this may require waiting a long time in tests dominated by wellbore storage (page 34, top).

Lengthy wellbore storage can totally mask earlier flow regimes that occur for certain borehole-formation configurations and formation types, causing distinct perturbations (continued on page 34).

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Elements of a conventional two-stage buildup transient test. Testing engineers use the first flow period to clean up formation damage and adjust the choke to gauge the producing capacity of the well. The first buildup provides a first estimate of reservoir pressure. Then begins a long flow period, followed by a longer buildup. Analysis of the transient measured during this second buildup reveals details of the near-wellbore region, formation characteristics such as permeability, and distant limits of the reservoir.

Traditional analysis centered on the Horner plot (middle), in particular the straight-line trend that signals radial flow. Today, the log-log plot (bottom) of $\Delta p$ and the derivative, the slope of the Horner plot, is used to first diagnose the various flow regimes of the transient. Then, specialized plots such as the Horner plot are used to estimate specific parameters such as permeability, skin and reservoir pressure.

A pressure transient breaks into several regimes on the log-log plot, each seeing deeper than the last. The first regime typically reflects wellbore storage, during which both the pressure and derivative curves overlay and increase along a straight line of unit slope. As wellbore fluids stabilize, pressure continues building up, but at a slower rate. The derivative curve swings down, eventually flattening out as the transient moves far enough from the wellbore to achieve radial flow. Since the radial-flow regime is a straight-line trend on the Horner plot, the derivative curve on the log-log plot is constant and traces a horizontal line. The interpreter’s first task always is to identify this derivative plateau, but this may require waiting a long time in tests dominated by wellbore storage (page 34, top).

Lengthy wellbore storage can totally mask earlier flow regimes that occur for certain borehole-formation configurations and formation types, causing distinct perturbations (continued on page 34).
on the derivative response. The signs are varied (next page). A partially penetrated formation produces a linear trend on the derivative curve with a slope of $-1/2$. In wells where the formation is strongly layered or naturally fractured, the derivative tends to dip before it rises to the radial-flow plateau. If wellbore storage is not too dominating, the transient can be analyzed to pinpoint the most likely explanation.

The last regime on the log-log plot occurs when the pressure transient has travelled far from the well and encounters the reservoir or drainage-area limits. Testing theorists have worked out the transient response to a catalog of boundary geometries (right). In most cases, the transient responses alone do not offer enough differentiation to enable the interpreter to definitively establish the boundary type. The choice of the type as well as the orientation of the boundary geometry must be guided by geologic, seismic and log data.

There are three categories: no-flow boundary, constant pressure boundary and the special case in which the test is long enough to reach all the no-flow boundaries, thus forming a closed system. Examples of no-flow boundaries include sealing faults—perhaps several of them—pinchouts, and channels. Because no-flow boundaries reflect the transient back toward the well, they cause $\Delta p$ to rise at higher than its normal radial-flow rate, so the derivative curve jumps to a higher level. A sealing fault causes the plateau value to double. With two intersecting sealing faults, the jump is correspondingly higher. If a fault is partially sealing, the derivative curve starts to jump but then falls back to its radial-flow value.

Constant-pressure boundaries, like a gas cap or aquifer, allow the pressure transient to flatten out at the boundary pressure, so the derivative takes a nosedive, which is instantly recognizable. In a closed system, pressure is completely contained within the reservoir. How this affects the $\Delta p$ and derivative curves depends on whether the transient is a drawdown or buildup. In drawdown, both curves track a line of unit slope, again an easily recognizable effect. In buildup, the derivative curve starts moving toward the line of unit slope but takes a nosedive before reaching it, somewhat similar to the constant-pressure boundary case.

These reservoir models are simpler than nature generally allows—in reality, a mixture of responses should be expected. Thanks to the superposition principle, however, responses may be combined to produce a realistic transient response for even the most complex situation. Simulating data, though, is the easier forward task. More different...
Response of log-log plot (left column) to several common reservoir systems, showing different flow regimes (see legend). The log-log plot is used by analysts to diagnose the flow regimes present in the transient. Once regimes are identified, the Horner plot (semi-logarithmic) and other specialized plots (linear) are used to evaluate parameters characterizing the system.
difficult for the analyst is the inverse procedure of finding the best model to match actual test data (below). For the traditional test comprising two flow periods and two buildups, transient analysis focuses on the second buildup. The first step is to identify the various regimes on the log-log \( \Delta p \) and derivative-curve plots and then choose the most likely model for each. Estimation of model parameters is then made using specialized plots that allow a focused analysis of each flow regime (previous page). For example, wellbore storage in the early data is determined from the slope of the straight-line portion of a linear \( \Delta p \) versus \( \Delta t \) plot. Confirmation and characterization of a vertical, high-conductivity fracture, recognized by a half-slope derivative trend on the log-log plot, come from a plot of \( \Delta p \) versus \( \sqrt{\Delta t} \). The radial-flow plateau is best analyzed using the generalized Horner plot. And so on.

Using a workstation, the reservoir engineer interacts with a computer program, such as STAR Schlumberger Transient Analysis and Report and ZODIAC Zoned Dynamic Interpretation Analysis and Computation programs; to build a comprehensive model using all the parameters found for the various flow regimes, predict what the entire transient should look like, and compare the results with the data. In this forward modeling process, the interpreter tweaks parameters, either manually or automatically using a nonlinear regression scheme, and perhaps alters the choice of model for one of the regimes to obtain the best possible fit. There may be several combinations of models that match the data equally well. In this case, other data must be sought to decide which model is the most appropriate (next page).

The final interpretation step, called history matching or verification, uses the model established in the second buildup to predict pressure response throughout all four periods of the test and confirms that the model satisfactorily accounts for all data. This may result in more parameter adjustment because every period must now be matched simultaneously, even though the second flow period is planned intentionally long to minimize the influence of previous periods.

In some cases, interference from earlier well manipulations may obscure key regimes of the transient being analyzed. Interpreters then resort to a process called desuperposition that attempts to isolate the transient from earlier ones and in particular reform the given transient's data to mimic how the reservoir would have reacted if the flow rate change had been an isolated, perfect step.

Designing well tests involves many of the same steps the interpreter uses. This is because once a test has been proposed, both the pressure data and the data's interpretation can be simulated to show that the test as designed meets its goals—design simulation requires estimates of formation and fluid parameters from nearby wells or the well in question. By predicting the likely shape of the log-log \( \Delta p \) and derivative curves, the engineer can demonstrate the feasibility of detecting and characterizing the anticipated reservoir features. For example, design simulation ensures that wellbore storage does not smother the feature being sought and guarantees a test that is long enough to view suspected reservoir boundaries. Another important feature of simulation is determining the accuracy and precision required of the pressure gauges.

The design phase not only maps out the mechanics of a test, but also ensures that, once underway objectives are met. For example, the progress of the planned transient can be followed at the wellsite and compared with that forecast during the design. To avoid the costly mistake of rigging down before the transient indicates a desired feature, wellsite validation of data during the test remains a must. This is best accomplished with surface readout of downhole gauges and enough computing power at the surface to produce appropriate plots, notably the log-log diagnostic plot. If the reservoir response is quite different from that assumed in the design, wellsite diagnosis permits an instant correction of the job, perhaps a lengthening of the transient, to
Finding the best model to fit the data. In this case, four scenarios fit quite well, but the dual-permeability model fits best. Dual permeability means a two-layered formation with a different permeability in each layer.

Integral to well test design is selection of hardware, which involves many options. To minimize wellbore storage, should the well be shut in downhole rather than at surface? In a low producer, will the act of shutting in actually kill the well? How sensitive must the pressure gauges be? To some extent, these questions are decided by the operator’s standard practices, the current status of the hole, the configuration of the downhole hardware and, not least, safety considerations.

The options have expanded in recent years. While drillstem test (DST) equipment has always guaranteed downhole shut-in in new wells, downhole shut-in devices for completed wells did not become commercial until the early 1980s. Pressure gauges have evolved from crude mechanical devices to quickly reacting, highly accurate quartz gauges. Perhaps the most unexpected innovation is a downhole flow measurement.

Traditional well testing theory dispensed with a flow measurement because it assumed constant wellbore storage, enabling flow to be estimated from early pressure data. But reality is less predictable. Wellbore storage often varies as the fluids in the wellbore change during the test, and a downhole flow measurement in fact offers a valuable complement to conventional pressure data.

Downhole flow measurements are currently performed using production logging...
The convolution integral that converts pressure response to a unit step change in flow, \( p(t) \), and actual measured flow rate, \( q(t) \), into measured pressure response, \( P(t) \). Convolution revolutionizes transient analysis when downhole flow measurements are available, for example as measured by production logging in a flowing test. The mathematical manipulation virtually wipes out wellbore storage, leaving later portions of the transient clearly visible.

During a test, downhole pressure gauges measure \( P(t) \) and a flowmeter measures \( q(t) \). But \( p(t) \) is what the interpreter wants. Getting at it requires the reverse process of deconvolution, which unfortunately is a rather unstable numerical procedure. More commonly, interpreters favor a procedure called logarithmic convolution that converts the two measurements more easily into something that fits existing analytical techniques (left).

Logarithmic convolution is a mathematical trick in which a form for \( p(t) \) is assumed—usually the response for infinite-acting radial flow—that simplifies the above convolution integral to a simpler expression involving a rate-normalized pressure \( P(t)/q(t) \), written \( f(t) \), and a new time-scale called sandface rate convolution time, \( t_{sfc} \). \( f(t) \) and its derivative with respect to \( t_{sfc} \) offer the same diagnostic power as the conventional well testing analysis described earlier with the advantage that most of the wellbore storage is removed.
There are several advantages to testing a well with downhole pressure and flow measurements under drawdown—and one disadvantage. The disadvantage is that reservoir shut-in pressure is not measured. The advantages are:

• in producing wells, little production is lost since the well is never shut-in.
• in poor producers, production is not killed as may occur during a shut in.
• in layered reservoirs, testing under drawdown reduces the possibility of crossflow between producing layers, while this can easily occur in a buildup test complicating the interpretation.

The technique’s most popular application in layered reservoirs, though, is in analyzing individual layer $kh$ and skin values. This involves measuring a series of transients created by changing the production rate, one for each layer with the production logging tool situated at the top of the layer (right). The amount of data acquired is huge and can be analyzed in several ways with varying degrees of sophistication. The key, however, is to first analyze the transient measured with the tool situated just above the bottom layer, yielding that layer’s reservoir properties. Then, a second transient is measured with the tool situated above the next layer, revealing reservoir properties of the new layer and bottom layer combined. Since reservoir properties for the bottom layer are already estimated, the transient can be analyzed to reveal just the new layer’s properties. The process continues up the well.

Layered reservoir testing (LRT) was originally conceived to investigate production wells. Recently in offshore Congo, AGIP used the technique to evaluate a layered reservoir encountered by an exploration well. Conventional testing of individual pay zones in an exploration well would normally call for a separate DST-perforation run for each zone. But using layered reservoir testing, AGIP obtained reliable $kh$, skin and productivity index values for individual zones with only one trip in the hole, at a considerable cost savings (see “Exploration Layered Reservoir Testing in the Congo,” next page).

The drawback of using an LRT in the exploration setting is that production from different zones commingles, ruling out representative sampling from different pay zones. Fortunately, a recent technological innovation provides a solution. Samples of extraordinary reliability may now be obtained from any number of zones using the new wireline-conveyed MDT Modular Formation Dynamics Tester, but this has to be planned in advance because the sampling takes place in open hole (see “The MDT tool: A Wireline Testing Breakthrough,” page 58).

In addition to convolution and layered reservoir testing, there are other advantages to supplementing conventional pressure data with production logging measurements. A flow profile run during stabilized production or shut-in can pinpoint where production is coming from and provide invaluable data on crossflow between zones. The information may directly influence testing interpretation. For example, if a zone is producing only from its upper part, a portion of the transient will react as if the well were only partially completed. The diagnosis must be adjusted accordingly. The fluid density measurement in production logging also plays a role by indicating whether gas is coming out of solution, giving a warning that a test may be occurring at below bubblepoint conditions.

Perhaps the most valuable contribution of downhole flow measurements is in testing (continued on page 45)

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Horizontal wells pose two special problems for the reservoir engineer. The first is the unavoidably large wellbore storage effect. Horizontal sections may extend for thousands of feet and cannot be isolated from the transient. The second is the more complex nature of the transient. Once wellbore storage is stabilized, three regimes possibly replace the radial-flow regime of a conventional test (right).

First is radial flow in a vertical plane toward the well, indicated by a plateau on the derivative curve on the log-log plot—this regime is termed early-time, pseudo-radial because permeability anisotropy (vertical to horizontal) actually causes an elliptical flow pattern. The second regime begins when the transient reaches the upper and lower boundaries of the producing zone and flow becomes linear toward the well within a horizontal plane. The derivative curve traces a line of slope $\frac{1}{2}$. The third regime occurs as the transient moves so far from the well that flow becomes radial again, but this time in the horizontal plane. The derivative curve enters a second plateau.

Although this makes diagnosis more difficult, it also offers benefits. As in conventional testing, the first plateau gives $kh$ and skin, but $k$ is now the geometric average of permeability in the vertical plane perpendicular to the horizontal wellbore trajectory, $\bar{k}_y$, $\bar{k}_z$, the wellbore trajectory being considered parallel to the $x$-axis. The intermediate linear flow period gives horizontal permeability along the $y$ axis, $k_y$, and the second plateau gives the average permeability in the horizontal plane, $\frac{1}{2}(k_y+k_x)$. In theory, the three regimes together can provide a breakdown of permeability into its three components.

The key to a successful interpretation is recognizing the first plateau, not only because this alone gives $k_z$, but also because it is the only regime that can directly provide skin. However, it is the regime most likely to get swamped by the large wellbore storage occurring in a horizontal well. The key to this dilemma is either downhole shut-in, or downhole flow measurements and logarithmic convolution.

Because of the length of a horizontal well’s producing zone, supplementing test data with flow profiles measured during production logging is even more crucial for pinpointing production and recognizing crossflow (see “Horizontal Well Testing in the Gulf of Guinea” page 42). Crossflow is common in horizontal wells as in vertical wells, particularly during a buildup test, and may seriously jeopardize interpretation.

The future of testing is assured, of course. What will accelerate its use and impact is better integration with other reservoir data, improved downhole pressure and flow sensors, further development of transient theory and a continued evolution of the interactive computer software that now aids interpreters.

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