In pursuit of increased quality and profitability, many in the manufacturing industry have found success in automating processes. The oil and gas industry is looking for ways to replicate this strategy for drilling. Drilling automation may hold the key to efficiently performing intricate and high-speed tasks and thus make complex wells technically and economically feasible. When a drilling project involves large numbers of wells drilled through well-documented lithologies and pressure regimes, operators can capitalize on the repetitive nature of automated drilling to eliminate costs associated with the performance variability typically exhibited from one well to the next within a drilling program.

Engineers have long viewed drilling as nearly equal parts art and science. Today, as autonomous computer-controlled drilling operations—drilling automation—approach reality, the view of engineers is leaning decidedly toward science. The ultimate objective of drilling automation, as with most upstream innovations, is to deliver financial benefits to the operator. Drilling automation seeks to accomplish this through process improvements, optimized rates of penetration (ROPs), consistent hole quality and overall drilling performance, all of which allow operators to reach their objectives in the shortest time.

Bringing together rig floor and downhole automation also promises to improve environmental protection and worker health and safety while helping operators to economically exploit reserves that are out of reach using today's technologies. As large numbers of upstream industry experts prepare to retire, automation may offer a way to codify best practices and knowledge and thereby preserve expertise.

On the manufacturing assembly line, automation has become ubiquitous, typically taking the form of computer-guided robots performing repetitive tasks. The machines are tireless, precise and do not suffer from the boredom or lapses in attention that their human counterparts do. They are able to attain a level of autonomy because there are few decisions to make and there is little uncertainty or variability in their environment and tasks. This is the concept behind the Factory Drilling approach for field development in which a large number of wells— for which conditions are well-understood—are to be drilled and completed.

The drilling industry has lagged other industries in adopting automation, but some advances have been made; high-end drilling units have been equipped with remotely operated iron roughnecks and pipe handling machines. However, while equipment mechanization replicates repetitive rig tasks on the drill floor and removes humans from potentially dangerous environments, it is not the same as drilling automation. An automated drilling process provides operators with a way of accessing reservoirs at lower costs while safely and consistently outperforming manual operations.

Automation of the drilling process requires a system that has the ability to deal with changing and uncertain environments. Fed directly by downhole and surface data, these systems must react to changes such as lithology in a manner that maintains optimal performance, thus increasing uptime and efficiency. Reduction of personnel on the rig floor and the system's ability
to perform some tasks remotely would be only by-products of this effort, not objectives. In practice, automated systems will more likely leverage the knowledge and experience of rig personnel than do away with them.

The drilling culture is part of the reason for the upstream industry’s delay in adopting automation. Drilling personnel often make operational decisions based on their overall experience and knowledge of the local geology and drilling conditions. As a consequence, many are suspicious of systems that seem a threat to their skill set, require them to relinquish some portion of control of the drilling operation or move technical limits away from traditionally conservative drilling practices. From an organizational point of view, the major components of an automated system require close cooperation over long periods of time, but the systems employed in the drilling process are often owned by a variety of companies and may have different drivers, making automated cooperation difficult.

The current challenge of creating an automated drilling system that is capable of drilling a well or section autonomously lies in the many uncertainties associated with making a hole deep in the Earth. In manufacturing industries, dramatic events encountered during the process are the exception, whereas in drilling, they are the rule. Downhole pressures, temperatures and rock characteristics often change rapidly as the bit progresses toward TD. Therefore, it is difficult to replicate an experienced driller’s response to any of the many possible scenarios.

Automating the drilling process hinges on not only availability and interoperability of computer-controlled machinery but also on information management; gathering the right information at the right time and coupling it with the experience necessary to make optimal decisions. The industry has long used software that assists drillers in making decisions on the rig floor. These systems require human intervention to interpret.

2. The technical limit is the best possible drilling performance for a given set of parameters. It is an ideal standard, which requires a perfect set of conditions, tools and people.
data and carry out the appropriate actions, providing drilling guidance rather than automation.

An automated drilling process requires a systems engineering approach—a loop that integrates real-time downhole and surface data with predrill models. Adjusting to changing conditions, this system modifies operational settings, such as pump rates, hook load and rotary speed. In addition, an automated system updates the model using real-time data, essentially simulating the decisions of an experienced driller adapting to the results of imperfect predictions. The level of integration between surface and downhole systems varies considerably and is limited by sensor availability near the bit and along the drillstring and by bandwidth to send measurements and commands to and from downhole. This means the character of drilling automation is likely to vary from well to well. However, results show that higher frequency data from more sensors improve operator ability to drill to the technical limit.

The path to drilling automation may be described in terms of three tiers. The first tier is a system that offers guidance to drillers, the second makes decisions with driller approval and the third moves toward an autonomous system in which the driller—who may be located off site—acts as the monitor, to intervene only when required (below).

The drilling industry has taken hesitant steps toward automation. Built and tested around 1980, the National Automated Drilling Machine was an early attempt to build an automated drilling rig. Because manufacturers could not overcome the failure of fragile sensors in a drilling environment, the machine was never commercialized. In the 1990s, many rigs were built with mechanized pipe handling equipment, and engineers developed closed loop control, using data gathered while drilling, to adjust rotary steerable drilling systems.

Only recently, driven by Norwegian operators and regulators concerned with safety and health issues, has the industry made a sustained effort toward drilling automation. In 2007, the SPE created a technical section devoted to drilling systems automation; those involved in the section are working toward automation in all areas, including completion and production. This article examines the state of those ongoing efforts to bring to the industry a level of drilling automation as a means to more efficient, safer and higher quality drilling operations in the future. Case studies from Mexico and the US illustrate various drilling automation applications.

**Controlling the Brake**

Historically, in an imitation of manual drilling operations, automated drilling has centered on using the drilling line brake to control weight on bit (WOB). Autodrillers, which mimic human operators by using pneumatic controls to on bit (WOB). Autodrillers, which mimic human operators by using pneumatic controls to

**The path to automation.** Systems and industries move from manual to automated control systems in a predictable manner. Initially, in the first tier (bottom), the systems perform a limited analyze-and-advice function by suggesting an optimal course of action for the human operator to perform. In the second tier (middle), the semiautonomous automated system chooses the action and performs it, but only after receiving approval from the driller. In the third tier (top), the automated system is autonomous and informs the driller of its actions as it takes them.

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**Tier 1**

1. Offers no assistance; driller must make all decisions and take action.

**Tier 2**

1. Allows the driller a restricted time to veto an action before automatic execution.
2. Selects and executes a suggestion if the driller approves.
3. Offers a set of alternatives and narrows the selection.
4. Offers a complete set of decision and action alternatives.
5. Offers no assistance; driller must make all decisions and take action.
6. Executes an action automatically and informs the driller only if it takes action.

**Tier 3**

1. Decides everything and acts autonomously.
2. Executes an action automatically and informs the driller only if it takes action.
3. Executes an action automatically and informs the driller only if asked.
4. Suggests a single course of action.
5. Offers a set of alternatives and narrows the selection.
6. Allows the driller a restricted time to veto an action before automatic execution.

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^ The path to automation. Systems and industries move from manual to automated control systems in a predictable manner. Initially, in the first tier (bottom), the systems perform a limited analyze-and-advice function by suggesting an optimal course of action for the human operator to perform. In the second tier (middle), the semiautonomous automated system chooses the action and performs it, but only after receiving approval from the driller. In the third tier (top), the automated system is autonomous and informs the driller of its actions as it takes them.
driller must anticipate what the system is going to do next. Therefore, counter to preconceptions held in the industry, human involvement in drilling operations may be increased rather than decreased by automation.

**Faster**

Engineers are applying these requisite computer control algorithms to various aspects of the drilling process; the algorithms fall in each of the tiers on the path to full automation. Most programs based on these algorithms act in an advisory capacity and require human intervention to initiate action. Others are, or are nearly, autonomous systems, which take action without seeking permission from or notifying the driller and might be best described as supervised autonomy. One such algorithm helps optimize ROP and has been used in programs that have both advisory and full-control capacities.

Automated ROP optimization relies on the fact that while the bit is on bottom, the driller can control only three things: WOB, drillstring rotation speed in revolutions per minute (rpm) and mud flow rate. An automated ROP optimization system can therefore be created in which the set points of WOB and rpm are fed directly to the controls of the drilling rig.

Modern autodrillers. Whereas WOB was the only parameter considered by early autodrillers as input for controlling the drilling process, later autodrillers used multiple parameters. In this example of multiparameter autodriller output, the multicolor horizontal bar at the top indicates by color which parameter is controlling the brake at that point. The solid curves at the bottom represent parameter data and the dashed lines are the parameter set points. The horizontal black line across the middle of the graph shows the status of the autodriller. When the line is at the low value, the autodriller is off; the upper value signifies it is on. As the 90-ft (27-m) long stand is drilled through a fairly homogenous formation, the ROP function (red) controls when the autodriller is turned on and the bit is above bottom. When ROP reaches its set point, WOB and torque (dark blue and green, respectively) rise as the bit automatically finds bottom. Torque takes control as ROP and WOB level off. When torque is recognized as the limiting factor, the autodriller raises the torque limit and drilling continues on $\Delta P$ (light blue)—the standpipe pressure when drilling with a mud motor minus standpipe drilling pressure when just off bottom—through most of the stand, although ROP experiences brief intermittent control throughout the primary $\Delta P$ control period. Toward the end of the stand, WOB takes over as the bit encounters harder rock. (Adapted from Florence et al, reference 5.)

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3. The driller adjusts the block position to keep the weight on bit within a desired range. The weight on bit is calculated as the difference between the measured hook load, which is a measure of the amount of pipe suspended below the block, and a datum taken by measuring hook load when off-bottom.
The ROPO algorithm is based on a model of PDC bit–formation interaction and a data processing technique that detects changes in bit response. The PDC bit model assumes that bit–formation interaction is broken into three linear phases based on the depth of cut (below). During the first phase, when the bit is just starting to turn on bottom and before reaching critical depth, increasing WOB causes little increase in depth of cut and, consequently, low ROP. During the second phase, higher WOB results in an increased depth of cut. Phase three begins when this increased efficiency has led to the founder point—the time at which the fluid system is no longer able to adequately clean the face of the bit, and cutting efficiency is reduced.1

The ROPO module characterizes the bit response in real time and determines optimal values of rpm and WOB—within a set of complex limits that includes WOB, torque, surface rpm, ROP and motor limits—to achieve maximum ROP.1

In 150,000 m [492,000 ft] drilled through a range of environments, wells drilled in the ROPO advisory mode have shown an average 32% ROP improvement compared with the ROP in offset wells drilled manually or with an autodriller system (above). When the ROPO algorithm was used in closed loop automation, or control mode, during which it sent commands directly to the rig control system, ROP improvements were even greater, with the control mode wells experiencing a 53.1% ROP gain over the ROP in wells drilled in advisory mode.10

For operators involved in multiple-well projects, saving rig time consistently, without sacrificing wellbore quality, is a strong incentive to improve ROP. In the Burgos basin in Mexico, PEMEX planned to drill 400 wells, many of which are in the Comitas field where the lithology is well known. Typical drilling trouble spots included an 8¾-in. section through mostly shale and a 6½-in. section that is characterized by interbedded formations of shale and sand.

In their evaluations of the many wells already drilled in the Comitas field, engineers found that ROP averaged 23 m/h [75 ft/h] through the 8¾-in. section and 16.15 m/h [52.98 ft/h] through the 6½-in. section. Both rates are well below the technical limit. Engineers determined that reducing drilling time by increasing ROP represented a singular opportunity to improve project economics.

Engineers first selected wells that appeared to be good candidates for ROPO applications and then gathered relevant offset well data. Wells were then drilled in ROPO mode and the results evaluated against offset well results. Two comparisons were made with results from offset wells: rotating ROP and total ROP for the section. When the ROPO algorithm was used through the 8¾-in. section, the rotating ROP increased to 55.40 m/h [181.8 ft/h]. In the 6½-in. section, ROPO use increased average ROP to 25.2 m/h [82.6 ft/h]. Time savings in the 8¾-in. and 6½-in. sections were 37% and 38%, respectively.

Smother
In high-angle wells, especially extended-reach wells with targets that may have a horizontal displacement of several miles from the surface location, some engineers view high ROP as a secondary objective to well path accuracy. To plan an accurate trajectory, the directional driller must locate the wellbore in three dimensions and precisely execute holds and turns. The objective is a trajectory that is the most efficient path to a distant target or one that keeps the wellbore within often narrow depth ranges to maximize formation exposure.
In directional drilling, certain processes have already been automated. For directional drilling with a bent housing downhole motor, engineers at PathFinder, a Schlumberger company, have developed the Slider automated surface rotation control system. The system is designed to increase drilling efficiency of a bent housing motor when in sliding mode by repetitively rotating the drillpipe clockwise at surface, then counterclockwise without disturbing the toolface orientation of the BHA. The Slider system uses surface torque readings as feedback to an automated system that controls the rocking movement of the drillstring to minimize the sliding friction along the toolstring. At the same time, the system reduces the need to pull the bit off bottom to reset the toolface.

When using bent housing mud motors to change BHA direction, directional drillers must often halt drilling. The Slider control system, however, allows BHA directional change without halting drilling and as a consequence may enhance overall ROP, a secondary objective. For example, when engineers used the Slider system in the build section of a well in Wood County, Oklahoma, USA, they increased sliding ROP by 118% compared with results from manual operations (below).

In contrast to mud motors, rotary steerable systems (RSSs) do not involve sliding sections so they generally deliver faster ROP and smoother wellbores. Additionally, because the drillstring rotates while drilling, hole cleaning is more efficient than when sliding. Therefore the well may be drilled with a lower pump pressure, which reduces the equivalent circulating density and reduces the threat of fracturing the formation.

For most rotary steerable systems, transmitting steering commands from surface to the RSS tool is accomplished using manually

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9. Though rpm and WOB are set by the system, they can also limit the system. For example, a PDC bit design may include maximum allowed WOB or rpm recommendations to prevent bit damage.
12. Equivalent circulating density, or ECD, is the effective density exerted by a circulating fluid against the formation. The ECD is calculated as: 
   \[ \text{ECD} = \frac{d + P}{(0.052 \times D)} \]
   where \( d \) is the mud weight in pounds per gallon (lbm/galUS), \( P \) is the pressure drop in the annulus between depth \( D \) and surface (psi), and \( D \) is the true vertical depth (ft).
controlled timed variation in mud flow; the driller manipulates the mud pumps to change tool settings. By allowing the steering command to be sent directly to the mud pump controller via a digital signal, directional drillers are able to control the well trajectory remotely.

Many rotary steerable systems today are equipped with a degree of autonomy. For example, hold inclination and azimuth commands, sent from the surface to the PowerDrive RSS, compel the BHA to maintain a constant course without further intervention from the surface. The PowerV vertical drilling system maintains a vertical trajectory, without human intervention, by sensing forces acting on the BHA that may cause it to deviate and then steering back to vertical.

Such a remote automated steering operation was performed in the 12¼-in. section of the Jacinto 1002 well located about 150 km [93 mi] from Villahermosa in southern Mexico. The only offset well, the Jacinto 1001, encountered very hard sands that caused low ROP. The formation in this section consists of intercalated zones with unconfined compressive strengths ranging from 41 to 83 MPa [6,000 to 12,000 psi], which cause high BHA vibrations and abnormal bit wear.

To address these challenges, drilling engineers used a directional drilling system that combined RSS tools with a mud motor power section. This system, which delivers more energy to the bit, mechanically decouples the bit from the drillstring, thus dampening vibrations above the motor because the drillstring rotates at a lower rpm than the bit and RSS. Engineers sent 21 automated downlinks to the RSS tool from a remotely located control center to build the curve, keeping the well tangent to the next casing point and drilling the 12¼-in. section with a single bit (above left).

Schlumberger engineers are developing an automated trajectory control system that receives real-time survey data to characterize the steering behavior of a BHA. The system uses that real-time downhole information to create more-accurate projections and determine the appropriate steering command to keep the drilling tool along the planned trajectory. Currently, the system is used in an advisory capacity, but an updated version in field tests will be able to act autonomously, issuing downlink commands to the tool to make it a fully automated trajectory control system.

Changing or unexpected formation characteristics may cause bit or BHA dysfunction, requiring continuous adjustments to the WOB and rpm in response. Using surface measurements, an engineer may have difficulty recognizing a change or its cause at the time it is encountered. Usually, there is a significant time lag between the time an event occurs and when the driller recognizes it and takes the proper corrective action. Given the lag and the many factors influencing surface readouts, it is not surprising when a driller makes an incorrect decision—one that is at best ineffectual and at worst detrimental.

A new automation array has the potential to overcome this shortcoming. The array consists of two elements: newly developed downhole sensors capable of high-frequency sampling and wired drillpipe capable of transmitting the resulting high volumes of data to the surface. By interpreting large volumes of data quickly, these automated systems alert drillers in real time to
threatening BHA phenomena such as stick-slip, whirl, axial shock and bit bounce.15

Wired drillpipe makes it possible to gather annular pressure and temperature measurements along the drillstring, which allows operators to monitor the entire wellbore. Algorithms quickly condense these data and convert them into flags and control signals for the automation system (above). Other algorithms sort the data, recognize an event and bypass the driller to initiate proper corrective actions if necessary.

Automatic Fluids Measurements
One of the most important factors influencing the success of drilling operations is the operator's ability to maintain drilling fluids properties within a prescribed range of values. Automation of the well construction fluids (WCF) domain addresses four major systems. In addition to the fluids, the WCF domain also encompasses flow conduits, tanks and process equipment. These four systems in turn fall into four areas: fluids treatment and pumping, downhole, solids control and waste management (previous page, bottom).16

The emergence of managed pressure drilling (MPD), in which engineers use a choke to regulate backpressure on the well to preserve a constant bottomhole pressure (BHP), has been instrumental in the drive to automate the WCF domain.2 The set point for the choke is determined using a hydraulic model. The hydraulic model is built and updated continuously during drilling operations using rig-supplied data such as flow rate, bit depth, rpm, torque and mud density, temperature and rheological parameters. Because fluids parameters are measured manually and because there is often a time lag between when a sample is collected and analyzed and when it is input into the model, the measurements may represent a source of error in the model.18

Recently, two Norwegian operators asked M-I SWACO, a Schlumberger company, to develop automated drilling fluid sensors. In response, a team of M-I SWACO engineers, working with regulators and supported by the operators, developed several sensors, most of which were custom developed or adapted from other industries. Engineers for this fluids measurement automation project began by determining that while most fluids measurement tasks could be executed remotely, fluid analysis must be performed on site and monitored remotely. Engineers identified existing sensors that allow fluids measurements to be accomplished remotely and determined which additional sensors required development.

Traditionally, engineers determine particle size distribution (PSD) using a series of sieves. Recently developed techniques rely instead on image analysis and require sample dilution in opaque fluids. One such technique uses an automated FBRM focused beam reflectance measurement instrument. The sensor is installed directly in a 5-cm [2-in.] flow loop leading from the active flow pit or the flowline where it measures the PSD of the fluids entering the well or exiting the annulus at one-second intervals (above).19

Engineers designed an automated elemental analysis and solids content instrument to replace conventional retorting procedures and manual chemical titrations. The new analysis tool uses a 500-eV source and a sensor that can be moved along three axes and is capable of monitoring any element with an atomic weight greater than that of magnesium. It can also measure high- and low-gravity solids content. Analysis may be displayed in existing graphical interfaces as concentrations of the various additives used in the fluid formulation.

To create an automated rheometer, the team focused on exploiting existing software and expanding instrument temperature range capabilities. To do so, they based the rheometer design on the Couette bob and sleeve API specified layout and the 10-second and 10-minute gel strength measurements.20 The primary change to the standard equipment was an electronic load cell to replace the spring attached to the bob that measured torque. The load cell is designed to improve accuracy by reducing the effects of temperature on measurements.

The data from the automated rheometer are exported directly to software that updates flow and pressure simulations for comparison with real-time downhole data reported from the rig. The software also prepares and reports test data directly in wellsite information transfer standard markup language (WITSML) to be displayed on graphical user interfaces (GUIs).

An automated electrical stability (AES) instrument was built and designed for the project to change the high-frequency electrical stability test from a single-point to a trend analysis. Trends may then be displayed beside other measurements such as oil/water ratios and viscosity. Each test sequence includes seven measurements; the software excludes the extremes and the remaining five are averaged, recorded and displayed as a trend on a GUI. The AES meter includes real-time capacitance measurements of oil-base drilling fluids and is installed directly on the rig flowline. Engineers are thus able to identify instantaneous trends in water content variation.

20. Mud shear stress is measured after a mud has set quiescently for a period of time. The times called for by the American Petroleum Institute procedure are for 10 seconds and 10 minutes, although measurements after 30 minutes or 16 hours may also be made.
Density measurements using dual real-time sensors present analytical trends and represent a significant change from standard API measurement techniques that use a conventional industry balance. Unlike the balance method, the new density sensor provides real-time updates of static and dynamic downhole pressures corrected for temperature variations.

Because the vibrating tube densitometer commonly used today is able to transfer temperature and density data from the sensors directly into the simulation software, engineers at M-I SWACO incorporated the densitometer into the project. As a consequence, data may be used in simulation software and shown on GUI displays located on rigs and in remote operations centers.\(^7\)

**Interoperability: The Bridge to Automation**

As sensor and software capability expands and is further enabled by increased network capacity, the type and number of well construction tasks being moved from human control to machines continue to increase. New automation algorithms have provided substantial gains in reliability and tool performance, and operators wishing to take advantage of these algorithms will inevitably move the industry toward drilling automation. As part of that process, operators will also drive the creation of standards to facilitate deployment of these algorithms.

A fully automated drilling process depends ultimately on the ability of all the components to share information. This requires that many parts and processes sift, select and act upon an enormous amount of data autonomously and synchronously. LWD and mud logging illustrate why a data aggregator system that gathers and coordinates various data sources must be developed before true drilling automation will be possible. In most cases, LWD tools transmit their data to the surface via mud pulse, which must be then translated into usable data. This means the data are not available to the user in real time but in near real time. Similarly, drill cuttings used as a data source by mud logging systems are not available until they are circulated to the surface. Such data may be captured and analyzed, which may be a matter of hours after they are created.\(^5\)

To efficiently use these data to automatically and appropriately respond to the drilling situation requires systemwide interoperability—the linking of people, tools, equipment and information at the right time and in the context of the drilling operation (above). Complete interoperability is fundamental to automation. Limited interoperability results in islands of automation that must be pulled together by humans to assure proper system interaction. Alternatively, custom solutions incorporated onto a select number of rigs are costly and also require human intervention. Rig contractors may offer a fast path to interoperability by providing remote control systems, but this approach may also be hampered by systems that are configured for specific rigs, contractors or rig types.

Improvements in the movement of and access to real-time data are also needed. Engineers are now working to apply to the drilling industry a unified architecture standard, which offers a unified data access technology stack that combines the lessons learned in process control with the automation used in aircraft, automobile, space and other industries. Engineers working on drilling automation are particularly interested in how these industries use existing standards, security configurations and certifications and real-time interoperability technologies to address redundancy and reliability. Of special interest for automated drilling scenarios is how other industries have addressed the concepts of situational awareness, human interaction and planning and system contingencies in the face of unexpected events.

Drilling contractors, service companies, equipment manufacturers and operators use various standards for data portability. WITSML is used most commonly in the oil industry to standardize the interfaces between various well monitoring and control technologies and software programs.\(^2\) A new standard or extension of an existing standard such as WITSML to describe rig and surface equipment is also needed but will require the combined efforts of operators, service companies, rig contractors and equipment suppliers.

For automation to occur on a wide scale, rig control standards must be applied industrywide. In addition to providing uniformity across all automated drilling units, contractor compliance with these standards will afford service providers a reliable platform upon which to integrate their solutions. Such a platform must allow a generic view of the rig from a programmatic standpoint. Once that is accomplished, conversion to specific rig platforms and specific rig contractor protocols will be necessary, requiring significant custom coding and rig time to assure each application is correct. Though early adopters of automation will pay for its development internally, they will reap the financial benefits of automation early, and standardization will help reduce overall costs and engineering time. —RvF